

**December 2000**

**The Structure of Electricity  
Distribution Charges  
Initial Consultation Paper**

## Executive summary

This document sets out background information on the form and structure of charges levied by each electricity distribution business for use of its distribution system. There are a range of factors that may affect the way in which distribution businesses set such charges. The purpose of this paper is to identify the key issues in respect of the methods and principles used in setting distribution charges and to assess whether in light of recent changes to the structure and operation of the electricity industry these methods and principles remain appropriate.

Charges that reflect the costs imposed by customers and other users of the distribution system provide economic signals which may encourage efficient use of and investment in the distribution network. This paper examines the extent to which cost reflective pricing is desirable and practicable in respect of charges for use of the distribution systems.

As well as discussing the overall approach to the structure of distribution charges this paper examines a range of specific issues including the averaging of charges across rural and urban customers, whether differences in charges for domestic and non-domestic customers reflect differences in costs, and whether the present balance between fixed and variable elements of charges remains appropriate. It also considers matters relating to embedded generation, energy efficiency and connections.

Ofgem intends to hold a public workshop during early 2001 to discuss these issues further with a view to developing initial proposals in Spring 2001.

This paper also develops material set out in the June 2000 consultation paper on distribution networks and NETA<sup>1</sup>. The June 2000 paper examined two types of issues. First, whether the existing incentive framework on distribution businesses, embedded generators and suppliers should be adjusted to take account of the revised attribution of imbalance costs resulting from NETA. Second, whether there should be compensation payments for generators and suppliers incurring imbalance costs as a result of distribution constraints and failures. This paper suggests that:

- ◆ distribution businesses should be required to improve the information available to embedded generators and suppliers in respect of network constraints and

failures, and report on the quality of service experienced by embedded generators; and

- ◆ at this stage it would not be appropriate to introduce new compensation payments for embedded generators and suppliers experiencing interruptions in distribution network availability.

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# 1. Introduction

## *Structure of electricity distribution charges*

- 1.1 There are fourteen licensed electricity distribution businesses in Great Britain (twelve in England and Wales, and two in Scotland). Each of these distribution businesses owns and operates the distribution network in its authorised area and sets charges for distribution use of system and connection. There are significant differences in the level and structure of the charges between each distribution business and authorised area. This contrasts with the position in the gas industry, where there are only small differences in the level of charges for distribution across the thirteen Local Distribution Zones (LDZs) owned and operated by Transco.
- 1.2 Many of the services provided by a distribution business, such as use of system, are not subject to competition and so Ofgem has put in place price controls to constrain the overall level of distribution charges. Distribution businesses charge supply businesses for use of the system, which in turn have to decide how to recover these costs from customers. Therefore, the structure of distribution charges is of interest to both suppliers and customers. This consultation paper identifies the key issues in respect of the methods and principles adopted by distribution businesses in setting charges for use of the distribution networks and invite views on whether these remain appropriate and what changes, if any, might be desirable.
- 1.3 There have been a number of wide ranging developments in the electricity industry in recent years, including the introduction of competition in the supply of electricity to all customers. The introduction of new electricity trading arrangements (NETA), the development of transmission access arrangements, and Government initiatives to promote renewable and embedded generation may also influence the future operation of the electricity distribution sector.
- 1.4 The Utilities Act 2000 sets out the statutory duties and functions of the Gas and Electricity Markets Authority, including the primary duty to protect the interests of consumers, wherever appropriate by promoting effective competition. Other duties include a duty to promote efficiency and economy of those authorised to

transport electricity. In the light of these statutory duties and functions, the review of the structure of electricity distribution charges will consider whether charges for connection to and use of the distribution systems provide appropriate signals to secure efficient use of distribution networks.

- 1.5 It is not clear to what extent the existing structures of distribution charges:
- ◆ reflect the costs of operating and maintaining the distribution network;
  - ◆ provide appropriate price signals to encourage efficient network investment;
  - ◆ facilitate effective competition in supply, connection, metering and generation activities; and
  - ◆ are consistent with the existing statutory and licence obligations placed on distribution businesses.

In addition, in future it will be necessary to take account of any statutory guidance issued by the Secretary of State in respect of social and environmental matters.

### ***Distribution networks and NETA***

- 1.6 In June 2000, Ofgem published a consultation document setting out its thinking on the key issues relating to the interaction between distribution networks and NETA. The document invited views on two types of issues:
- ◆ whether the existing framework of incentives on distribution businesses, embedded generators, customers and their suppliers, should be modified to take account of the revised attribution of imbalance costs that will result from the introduction of NETA; and
  - ◆ whether there should be compensation payments for embedded generators and suppliers incurring imbalance costs as a result of distribution constraints and failures. Furthermore, whether distribution charges to generators and suppliers should be increased to recover the costs of these payments.

- 1.7 The June paper indicated that following consideration of the responses to the paper, discussions with interested parties, and the report of the DTI/Ofgem working group on embedded generation issues, draft proposals would be published in Autumn 2000.
- 1.8 Publication of the findings of the DTI/Ofgem working group will now be in early 2001. It will be necessary to take account of these recommendations in formulating any proposals. Nevertheless, this paper sets out Ofgem's further thinking on the interaction between distribution networks and NETA.

### ***Structure of the document***

- 1.9 Chapter 2 describes the present regulatory framework that governs the way distribution businesses operate and maintain their distribution networks. Chapter 3 provides background information on the characteristics of distribution networks, the existing structure of distribution charges, and the methods and principles used by distribution businesses in setting these charges. Chapter 4 discusses the distribution charges that are levied on different groups of customers, the extent of fixed charges, energy efficiency, charges for embedded generators and the boundary between connection and use of system charges. Chapter 5 provides Ofgem's further thoughts on the interaction between distribution networks and NETA, in light of responses to the June 2000 Distribution Networks and NETA consultation paper. Chapter 6 describes the consultation process and the timetable for the review going forward. Appendix 1 summarises the responses to the June 2000 Distribution Networks and NETA consultation paper. Appendices 2 to 14 describe the methods and principles adopted by each distribution company business for setting use of system charges.

### ***Rationale***

- 1.10 While the overall level of revenue recoverable from distribution charges is subject to price control, each distribution business presently sets the structure of its charges, subject to certain broad constraints relating to matters such as price discrimination. Distribution charges account for a significant proportion of final bills (about 30 per cent for a typical domestic customer). The structure of distribution charges may also have a bearing on the development of competition

and so will be a matter of interest for suppliers, embedded generators and customers alike. There is also a statutory duty on distribution businesses to facilitate competition in the generation and supply of electricity.

- 1.11 The direct costs of the structure of charges review are estimated at less than £0.1 million. The direct costs to the industry are expected to be small and, so far as Ofgem is aware, no company is using consultants. The costs of implementing changes to the structure of charges will depend on the outcome of the review and on the companies' management and IT systems. Nevertheless, these costs are not expected to be significant in the context of the importance of distribution charges to the efficient operation of the electricity industry and the development of competition.

### ***Interaction with other projects***

- 1.12 This consultation paper identifies a number of issues that are presently being considered within the scope of other projects impacting on the industry, such as:

- ◆ the information and incentives project (IIP);
- ◆ NETA and transmission access arrangements;
- ◆ the DTI/Ofgem working group on embedded generation issues;
- ◆ the review of Guaranteed and Overall Standards of Performance;
- ◆ the review of competition in connections; and
- ◆ the environmental action plan.

- 1.13 It will be necessary to consider the key issues in respect of the structure of electricity distribution charges within the context of these other initiatives and policy areas.

***Responding to this document and an invitation to the public workshop***

- 1.14 It would be helpful to hear from those with an interest in the issues raised in this paper, including distribution businesses, suppliers, embedded generators, customers and their representatives. Views are invited by 31 January 2001. Where possible responses should be sent electronically to:

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Economic Adviser  
Distribution & Financial Affairs  
Office of Gas and Electricity Markets  
9 Millbank  
London  
SW1P 3GE  
Fax: 020 7901 7478  
Tel: 020 7901 7143  
E-mail: colin.green@ofgem.gov.uk

Responses will be published by placing them in the Ofgem library. If you have any queries concerning the issues raised in this document, please contact Colin Green on the above number or Richard Clay on 020 7901 7264.

- 1.15 Ofgem intends to hold a public workshop on the key issues raised in the paper in Early 2001 (date and venue to be confirmed). It would be helpful if those respondents interested in attending the public workshop could complete the contact form in chapter 6 and return it by post or fax to Colin Green by 15 January 2001.
- 1.16 A copy of this document is also available from the Ofgem website ([www.ofgem.gov.uk](http://www.ofgem.gov.uk)).

## 2. Regulatory framework

### *Introduction*

2.1 This chapter describes the main elements of the regulatory framework relating to distribution charges. These include:

- ◆ the Utilities Act 2000;
- ◆ price controls applying to each distribution business;
- ◆ minimum standards of service; and
- ◆ licence conditions to prohibit discrimination between customers or groups of customers.

### *Utilities Act 2000*

2.2 The Utilities Act 2000 sets out the duties and functions of the Gas and Electricity Markets Authority, in particular the primary duty to protect the interests of consumers, wherever appropriate by promoting effective competition. In carrying out these duties and functions, the Authority shall have regard to:

- ◆ the interests of consumers who are disabled or chronically sick, consumers of a pensionable age, consumers with low incomes, and consumers residing in rural areas;
- ◆ guidance issued by the Secretary of State in respect of social and environmental policies;
- ◆ the need to secure that all reasonable demands for electricity are met;
- ◆ the need to secure that all licence holders are able to finance their activities; and
- ◆ the promotion of efficiency and economy of distribution systems.

2.3 The Utilities Act 2000 also sets out the duties of a distribution business to develop and maintain an efficient, co-ordinated and economic system of electricity distribution; and facilitate competition in the supply and generation of electricity.

### ***Price controls and service standards***

- 2.4 In order to protect the interests of customers, the regulatory framework has been designed to provide and strengthen incentives on distribution businesses to increase efficiency so that prices can be lowered, and to give clear incentives to encourage businesses to provide an appropriate quality of service.
- 2.5 Many of the services provided by a distribution business, such as use of system, are not subject to competition and so Ofgem has put in place price controls to constrain the overall level of distribution charges. These arrangements provide incentives for each distribution business to minimise the operating, capital and financing costs of its activities. Ofgem has also set Guaranteed and Overall Standards of Performance, targets for customer minutes lost and the number of interruptions per 100 customers, to encourage distribution businesses to maintain and improve levels of service for customers.
- 2.6 Guaranteed Standards of Performance determine service levels that must be met in each individual case. If a company fails to provide the level of service specified, it must make a fixed payment to the customer concerned. Overall Standards apply to areas where it is not appropriate or feasible to give individual guarantees but where it is reasonable for customers, in general, to expect a minimum level of service.
- 2.7 The Guaranteed Standard GS2 specifies that payments of £50 and £100 are available for domestic and non-domestic tariff customers respectively if the distribution business fails to restore supplies within 18 hours of an interruption. Similarly, two of the existing Overall Standards of Performance (1a and 1b) require companies to aim to restore supplies to specified minimum percentages of customers within specified periods (respectively 3 and 18 hours) after an interruption. The target restoration rate for Overall Standard 1b is presently 99.5 per cent.
- 2.8 At present the incentives and information project (IIP) is examining options for strengthening the incentives on each distribution business to deliver appropriate levels of service for its customers. As a result of the IIP, Ofgem intends to introduce an enhanced output based incentive scheme from 1 April 2002.

2.9 Each distribution business is required to design its network to certain minimum standards. There are licence conditions that require distribution businesses to meet the network design standards set out in Engineering Recommendation P2/5. This specifies different levels of security for different sizes of electrical demand. These arrangements are complemented by the Electricity Supply Regulations, issued by the Secretary of State, which place a duty on distribution businesses to ensure a continuous supply of electricity is maintained except in special circumstances. The regulations also define limits for allowed variations in voltage level and set out requirements about the safety and adequacy of the network. These provisions influence distribution business costs and the quality of service that customers can expect to receive.

***Non-discrimination provisions***

- 2.10 Further protection is afforded to users of distribution networks in the form of licence conditions (Condition 8A in England and Wales, and Condition 2A of Part VI in Scotland) that require distribution businesses to provide services on a non-discriminatory basis. These conditions specify that distribution charges should not differ between customers or groups of customers except in so far as these differences reflect reasonable differences in the costs of providing those services. These conditions also prohibit a distribution company from setting charges for use of system that restrict, distort or prevent competition in the generation, distribution or supply of electricity.
- 2.11 These arrangements do not prevent distribution businesses from levying the same charges on customers that impose different costs on the system. For instance, these licence conditions do not prohibit distribution businesses from making the same charge for transporting electricity to similar customers located in rural and urban areas despite the differences in costs that these customers may impose on the distribution system.

### 3. Distribution networks

#### *Background*

- 3.1 Each licensed distribution business owns and operates the distribution network in its authorised area. These distribution networks comprise overhead lines, cables, transformers, switchgear, and other equipment to facilitate the transfer of electricity from the transmission system and generators connected directly to the distribution network (embedded generators) to customers' premises. Most customers are supplied at low voltage (LV), which is defined as a voltage less than 1kV, with domestic customers typically supplied at 230V. Larger commercial and industrial customers are typically supplied at high voltage (HV), which is defined as a voltage greater than 1kV, with the largest customers supplied at extra high voltage (EHV), which is defined as a voltage greater than 22kV.
  
- 3.2 While there are many similarities in the distribution networks operated by each distribution business, there are some important differences. For example, distribution businesses vary in size (in terms of geographical area, the number of customers connected to the network, or the quantity of electricity distributed), in the degree to which customers are dispersed across the network, in the proportion of different types of customers connected to the network, as well as in other ways. The following table summarises some of the characteristics of distribution networks.

**TABLE 3.1: DISTRIBUTION NETWORKS – 1998/99**

Distribution company	Area (Sq km)	Customers (000's)	Circuit length (km)	Proportion of circuits underground (%)	Quantity distributed LV (GWh)	Quantity distributed HV (GWh)	Quantity distributed EHV (GWh)
Eastern	20300	3322	89747	61	23919	7495	750
East Midlands	16000	2300	67751	64	15781	10403	535
London	665	2011	30160	100	17389	4660	295
Manweb	12200	1393	45313	53	9423	4340	3542
Midlands	13300	2260	63802	60	14969	10216	911
Northern	14400	1451	43937	61	9590	3848	2470
Norweb	12500	2140	58772	76	14943	8151	531
Seeboard	8200	2126	44773	73	14867	2985	1874
Southern	16900	2652	71934	61	20375	7195	2067
South Wales	11800	980	32873	43	6281	2664	3208
South Western	14400	1344	48009	39	10069	3368	737
Yorkshire	10700	2088	54268	71	13347	8118	1713
ScottishPower	22950	1870	64396	62	14894	5152	2322
Hydro-Electric	54390	640	44113	31	6618	1306	403
<b>Average</b>	16336	1898	21161	61	13748	5707	1526

- 3.3 As described in paragraph 2.9, each distribution business is required to design its network to certain minimum standards. These provisions influence the technical specifications of distribution networks and the quality of service that customers can expect to receive. The technical and demographic characteristics of each network will affect the costs of providing, maintaining, and operating the distribution system. The extent to which network characteristics differ across distribution businesses may affect differences in both the overall level and structure of distribution charges.
- 3.4 To encourage the efficient use of each distribution system, the charges levied by distribution businesses on suppliers should reflect the costs that customers impose on the distribution systems. For instance, the costs of transporting electricity to a particular point on a distribution network could reflect the costs of providing the network at that location, including any contribution to the costs of network reinforcement necessary to comply with network design and security standards.
- 3.5 In devising charges to encourage the efficient use of the distribution networks, it is important to consider the implications of short run and long run decisions. In the short run, there is a question of how to allocate existing resources efficiently, whereas in the long run there is a question of ensuring investment is made efficiently. Investment decisions are influenced by changes in the pattern and

level of demand which in turn are influenced by the structure of charges. In considering whether a particular system of charging is appropriate it is also necessary to take into account Ofgem's wider statutory duties and functions and any environmental and or social guidance issued by the Secretary of State.

### ***Charges for use of the distribution system***

- 3.6 Condition 8 of the Public Electricity Supply Licence in England and Wales (Condition 2 of Part VI in Scotland) deals with distribution charges. Under these licence conditions, distribution businesses publish statements of charges for use of system, connection and metering services. Many of these services are subject to price controls. Nevertheless, where charges are not subject to price controls, such as charges for connection to the distribution system, they are subject to competition and or disputes in respect of these matters can be referred to Ofgem for determination.
- 3.7 Distribution businesses determine the level and structure of use of system charges within the limits set out by the regulatory framework. Distribution businesses also have regard to a range of factors relating to costs, such as the voltage level at which customers take supply and the time at which electricity is transported over the system in setting charges. As a result, distribution businesses levy different charges to different types of customer.
- 3.8 Customers taking supply at lower voltages face higher unit charges for use of the distribution system than those customers connected at higher voltages. These differences broadly reflect the costs of providing additional network assets to facilitate the transfer of electricity to customers' premises connected at lower voltage levels. A distribution business will typically utilise the assets at and above 11kV to facilitate the transfer of electricity from the transmission system to a customer connected at 11kV. In comparison, a distribution business will also utilise those assets between 230V and 11kV, as well as those assets provided between 11kV and the transmission system, in transporting electricity to a customer connected at 230V.
- 3.9 Distribution use of system (DUoS) charges for each group of customers typically comprise fixed and variable elements. The fixed elements of charges, including standing charges, reflect the costs of providing services that are typically

customer related, such as the operation and maintenance costs of connection and metering assets, and customer service costs. Fixed charges may also reflect certain capacity related costs. The variable elements of charges typically reflect volume-related costs such as the costs of providing, operating and maintaining network assets.

- 3.10 Embedded generation may bring benefits to distribution networks in the form of reduced electrical losses, avoiding or postponing the need for system reinforcement and increasing security of supply. However, these benefits will largely depend on the location and pattern of output of each embedded generator. If an embedded generator is situated where demand is low or its output is erratic then it may impose additional costs on the distribution business. At present, distribution businesses levy connection charges on embedded generators. These charges will depend on a range of factors including the voltage of connection. Nevertheless, embedded generators do not pay charges for the use of the system when exporting energy. These matters are discussed further in chapter 4.

### ***Long run marginal or incremental cost pricing***

- 3.11 Long run marginal cost pricing is sometimes considered as a means for providing appropriate price signals to encourage efficient use and investment in the distribution network. Distribution businesses may define long run marginal costs as the cost of transporting an additional unit of electricity for a sustained period, including the costs of reinforcement or extension to the distribution system. Long run incremental cost pricing is a closely related concept, with costs measured in terms of a larger increment to demand, rather than an additional unit.
- 3.12 Despite the potential benefits derived from long run marginal or incremental cost pricing, these methods may be difficult to implement in practice. For instance, distribution businesses operate monopoly networks with substantial fixed costs. In order to allow distribution businesses to finance their activities over the long run, they must be able to recover the efficient costs incurred by the business and earn an appropriate rate of return on assets. However, the

marginal costs of distribution typically lie below average costs which suggests that marginal cost pricing will not fully recover costs.

- 3.13 Distribution businesses can preserve price signals by setting variable charges to reflect the structure of long run marginal costs and then applying a mark-up over costs to ensure that total costs are fully recovered. Various rules can be adopted to calculate an appropriate mark-up such that the distortions to price signals are minimised.
- 3.14 Economic theory suggests that price-cost mark-ups should be applied with reference to the responsiveness of demand in different market segments. The notion of Ramsey pricing implies that the mark-up should be higher in those markets where demand is less responsive to changes in price. Distortions in consumption and investment decisions are minimised since the price mark-ups are largest for customers with demands that are least responsive to price movements. Nevertheless, this approach is difficult to implement due to problems in correctly estimating the price responsiveness of customers. In addition, it would be necessary to consider carefully whether Ramsey pricing would have any significant implications for Ofgem's wider social and environmental objectives.
- 3.15 A multi-part tariff is an alternative approach where there is a lump sum charge that covers fixed costs and a variable charge that relates to marginal or incremental costs. However, it is often difficult to determine what proportion of fixed costs should be allocated to each customer group.
- 3.16 Other solutions that have been suggested include equi-proportionate mark-ups. Under this approach the incremental costs of the system are determined in the normal way and then raised by the same proportion to meet the total costs. One advantage of this approach is that it is a simple way to ensure full cost recovery and maintain relative price signals.
- 3.17 Long run marginal or incremental costs can be estimated with reference to the key cost characteristics or drivers. These drivers may include factors such as:
- ◆ the distance electricity is distributed;
  - ◆ voltage level of connection;

- ◆ geographical and demographic factors; and
- ◆ peak demand on the system.

***Methods and principles adopted by distribution businesses since privatisation***

- 3.18 Before privatisation, regional electricity companies determined the use of system component of final supply prices with reference to the methods and principles set out in a paper by Boley and Fowler (1977)<sup>2</sup>. This yardstick approach was designed to derive the long run incremental costs of the distribution system by assessing the costs of providing system assets at each voltage level. These costs were then allocated to customer groups on the basis of their contribution to peak load on the system. Since privatisation, most distribution businesses have adopted a broadly similar approach to that set out by Boley and Fowler, although it has been modified to reflect the constraints determined by the regulatory framework.
- 3.19 Using this broad approach, estimates of the long run incremental costs of the system are derived using a stylised model of the distribution network. This is typically constructed to reflect the specific changes in network design required to meet an additional 500MW of load. The model also reflects the load characteristics and customer mix of the company's existing network. The model is used to derive the incremental cost of providing system capacity at each voltage level. Estimates of costs are then allocated to customer groups based on the relative contribution to peak load on the system.
- 3.20 East Midlands Electricity has departed from the traditional approach set out by Boley and Fowler, in favour of a method where its prices and revenue streams better reflect the price control formula. Distribution charges are set with reference to the weights placed on unit charges within the price control formula.

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<sup>2</sup> The basis for cost reflective retail tariffs in England and Wales, T A Boley and G J Fowler, IEE Third International Conference on metering, Apparatus and Tariffs for electricity supply, London 1977.

3.21 In September 2000, Ofgem asked each distribution business to provide a statement demonstrating how its use of system charges are derived. In particular, businesses were asked to:

- ◆ describe to what extent the methods and principles adopted in setting charges differ from those set out by Boley and Fowler (1977);
- ◆ identify the key cost drivers reflected in use of system charges;
- ◆ describe how network asset costs are derived and explain how these costs are hypothecated to customer groups;
- ◆ describe the main activities associated with network operation and maintenance, and outline how these costs are calculated and then allocated to different customer groups;
- ◆ explain how the costs of electrical losses are treated;
- ◆ identify what other activities are captured within use of system charges and describe how these costs are allocated to different customers;
- ◆ explain how these methods and principles are modified to ensure compliance with the distribution price controls; and
- ◆ provide an illustrative example of how use of system charges for the standard domestic tariff (credit) are derived.

Responses from each distribution business are set out in Appendices 2 to 14.

### ***The way forward***

3.22 This section identifies the key areas for discussion in respect of the way distribution businesses set charges for use of their distribution systems, in particular whether it might be appropriate to adopt different methods and principles. Revised arrangements would require careful consideration, including how they might be implemented, how they might affect existing users of the network, the timing of any changes, and implications for the distribution price controls.

- 3.23 While the methods and principles of charging adopted by nearly all distribution businesses are broadly similar, there are some significant differences in the way these are applied. For example, some businesses derive system costs based on an assessment of the replacement value of the distribution system. Other businesses have opted to derive system costs based on the reinforcement costs of the distribution system. These factors will influence the calculation of distribution charges.
- 3.24 The approach set out by Boley and Fowler does not distinguish between the geographical distribution of costs in deriving use of system charges for the transportation of electricity to rural and urban customers. Instead, this approach emphasises the voltage level of connection. As a consequence, suppliers will incur the same charges for customers connected at the same voltage level. Views are invited on whether the principle of average charges for similar customer groups is appropriate, or whether charges should more closely reflect the geographical distribution of costs.
- 3.25 A number of alternative methods and principles might be adopted by distribution businesses in calculating electricity distribution charges, including charges calculated on the basis of geographical zones. Zonal charging is an approach adopted by NGC to reflect the broad costs and benefits that demand customers or generation capacity imposes on the transmission system at different points of the transmission network at peak periods. As a consequence, demand transmission charges tend to be higher in the south of England due to the high cost of transporting electricity over long distances, whereas generation transmission charges tend to be lower in the south to reflect the benefits that local generation brings in terms of reducing transmission costs.
- 3.26 This approach has an element of distance related charging, reflecting those costs and benefits imposed by generation and demand, located at different points on the network. There might be a number of difficulties in adopting this sort of approach for distribution charges. First, it would increase complexity. Second, it might lead to higher charges for customers in rural areas. Nevertheless, there may be advantages in considering a system of zonal charges for embedded generation and this is discussed further in chapter 4.

- 3.27 The method adopted by East Midlands Electricity in charging for use of its distribution system is a move towards a system of prices that better reflects the regulatory pricing framework. As described above, distribution charges are set with reference to the weights placed on unit charges within the price control formula. This has three main advantages:
- ◆ the divergence between regulated income and allowed revenue is minimised;
  - ◆ the level and structure of charges is largely predictable over the short and medium term; and
  - ◆ this approach is relatively simple to administer, avoiding the need for stylised assumptions used in traditional tariff setting models.
- 3.28 The main disadvantage of this approach to tariff setting is that it moves away from cost reflective pricing, in favour of increased tariff stability. Investment and consumption decisions may be distorted as a result. Nevertheless, the enhanced tariff stability that is achieved may better facilitate competition in the supply of electricity, to the benefit of consumers.
- 3.29 In the longer term it is not clear that the price control formula, which is primarily designed to constrain the overall level of regulated revenue should drive the structure of charges. At the next price control review Ofgem will consider changing the present form of control from an average revenue control to a tariff basket control. This will reduce incentives on distribution businesses to distort charges and could have additional advantages, such as avoiding the complications associated with correction factors and so increasing the stability of prices for all distribution businesses, suppliers and customers.
- 3.30 Transco operates the gas transportation network in Great Britain, which is divided into a National Transmission System (NTS) and thirteen LDZs. The LDZs are broadly similar to the fourteen regional electricity distribution networks operated by distribution businesses.
- 3.31 At present, Transco adopts average, or postalised, charges for use of the LDZ networks. These charges are derived according to load size, which acts as a proxy for the typical use of different parts of the system. Transportation charges

for customers with similar load requirements do not vary within LDZs.

Typically, customers with low load requirements tend to pay higher unit charges than customers with higher load requirements. These differences broadly reflect the additional assets used by low load customers.

- 3.32 Transco's methods involve two types of averaging. The total cost of using each pressure tier is averaged across the estimated peak and annual demands for that tier. Probability matrices are then used to estimate the use of each tier by customers within each load band. It has been suggested that the process of averaging distorts incentives for connection to the LDZs. Customers located near to the NTS may incur relatively high charges in respect of use of the LDZ networks, which may in turn incentivise those customers with large loads to bypass the LDZ networks and connect directly to the NTS. These incentives may discourage efficient investment, since bypassing the LDZs might require unnecessary infrastructure. As a consequence, Transco has introduced a short haul tariff for such customers.
- 3.33 It has been suggested that the process of setting LDZ charges with reference to load means that customers with significantly different load characteristics, such as different patterns of peak and off-peak consumption, may incur similar charges. This approach is not fully cost reflective.
- 3.34 Nevertheless, Ofgem's recent review of Transco's LDZ charging methods concluded that a move towards a more cost reflective approach to LDZ charging would involve significant costs. At present, these costs would appear to outweigh the potential benefits.
- 3.35 The development of competition in generation and supply, the introduction of NETA, and the anticipated growth in embedded generation as a consequence of Government climate change initiatives, will influence the requirements for access to the transmission and distribution systems. Ofgem is presently considering the introduction of revised transmission access arrangements.
- 3.36 Access to the distribution system for embedded generators, suppliers, and customers is limited to the connection capabilities of the site and this provides an upper bound on the aggregate access limits. Nevertheless, network constraints and failures on the distribution and or transmission systems may

reduce these limits. In practice the connection arrangements for embedded generators, suppliers, and customers do not confer firm access rights.

- 3.37 A small number of suppliers have suggested that following the introduction of revised transmission access arrangements, consideration should be given to introducing similar arrangements for distribution networks. As distribution networks tend not to experience the sort of capacity constraints that are common on transmission networks it is not clear to what extent similar arrangements will be appropriate. Nevertheless, following the introduction of revised transmission arrangements it may be relevant to reconsider the extent that connection agreements and distribution charges should confer firm rights of access for customers, suppliers and generators.

### ***Conclusions***

- 3.38 As described above, the yardstick method adopted by most distribution businesses is broadly similar to the approach set out by Boley and Fowler. Distribution use of system charges are derived with reference to an estimate of the long run incremental costs of providing the system. These costs are then allocated across customer groups relative to the load characteristics of the group. It has been suggested that this approach is broadly costs reflective, since charges are set to reflect the costs that a typical customer imposes on the distribution system. However, charges may not be fully cost reflective since similar customers incur the same charge despite being located on different parts of the network.
- 3.39 The approach adopted by distribution businesses may have several advantages in terms of facilitating competition in the supply of electricity. It has been suggested that, in general, this approach enables distribution businesses to derive a relatively simple structure of charges. As a consequence, suppliers are able to evaluate with a reasonable degree of accuracy the charges they will incur in respect of use of the distribution system, and structure end user prices accordingly.
- 3.40 It is important to consider whether it is desirable to adopt different methods and principles. There have been relatively few complaints about the principles adopted by distribution businesses in setting charges. In these circumstances it

is not clear there is a case for a significant change to the overall principles for setting distribution charges. Nevertheless, some concerns have been expressed about specific aspects of charges and or the methods adopted by companies in setting charges. These matters are dealt with in chapter four.

3.41 Views are invited on any aspect of the issues raised in chapters two and three and in particular on:

- ◆ the overall regulatory framework that governs the structure of electricity distribution charges;
- ◆ the broad principles adopted by each distribution business and the suitability of approaches to setting distribution charges based on the Boley and Fowler framework;
- ◆ the adjustments made to the Boley and Fowler framework to take account of the constraints imposed by the distribution price controls;
- ◆ the averaging of charges across rural and urban customers;
- ◆ the advantages and disadvantages of a tariff basket price control; and
- ◆ whether differences in the approaches to setting electricity and gas distribution charges unduly distort incentives or competition in energy markets.

## 4. Specific Issues for consideration

### *Introduction*

- 4.1 This chapter identifies a number of specific issues for consideration in respect of the distribution charges. These include the balance of charges across different groups of customers, the extent of fixed charges, the treatment of embedded generation, matters relating to energy efficiency and the boundary between use of system and connection charges. Modification to the existing structure of charges would require careful consideration, including how the implementation of revised arrangements might affect existing users of the network, the timing of any changes, and implications for the distribution price controls.
- 4.2 In setting charges, distribution businesses presently have regard to a range of factors that influence the costs of providing use of system, such as the voltage level at which customers take supply and the time at which electricity is transported over the networks. Nevertheless, the method and assumptions made in attributing or allocating costs to customers or groups of customers may influence the differences in the level and structure of charges between customer groups.

### *The balance of charges across customer groups*

- 4.3 Chapter 3 explains that customers taking supply at lower voltages incur higher unit charges for use of the distribution system than those customers connected at higher voltages. This reflects the need to provide a more extensive network to serve customers connected at lower voltages. Nevertheless, distribution businesses appear to estimate costs differently, with some businesses placing a greater emphasis on certain characteristics rather than others.
- 4.4 Table 4.1 summarises the average unit charges made by distribution businesses for the transportation of electricity to different types of demand customer in 2000/01. The table also shows the overall variation in charges levied by distribution businesses.

**TABLE 4.1: DISTRIBUTION USE OF SYSTEM CHARGES – 2000/01**

<b>Customer type</b>	<b>Great Britain average pence/kWh</b>	<b>Great Britain minimum Pence/kWh</b>	<b>Great Britain maximum Pence/kWh</b>
<b>LV Domestic</b>	1.60	1.14	2.38
<b>LV Non-Domestic</b>	1.26	0.80	1.69
<b>HV</b>	0.61	0.50	0.84
<b>EHV</b>	0.46	0.16	0.79
<b>Average</b>	1.13	0.90	1.44

- 4.5 Most distribution businesses differentiate between the costs imposed by domestic and business customers connected at low voltage, including those costs arising from differences in consumption patterns. As a result, domestic customers typically pay more per unit of electricity distributed for use of the distribution system than business customers connected at the same voltage level. Nevertheless, several distribution businesses make little or no distinction between the costs imposed by domestic and business customers connected at low voltage. As such, the use of system charges levied by these distribution businesses to suppliers in respect of domestic and business customers tend to be broadly similar.
- 4.6 Views are invited on whether, for the purpose of setting use of system charges, distribution businesses should estimate costs on a more consistent basis. This would tend to reduce some of the asymmetries between companies, but might lead to significant changes in charges for specific groups of customers.
- 4.7 Several large users have expressed concern about the way distribution businesses calculate EHV charges compared with the calculation of charges for transporting electricity to other customer groups. At present, distribution charges for customer groups connected below EHV are calculated with reference to the average costs imposed by these customers on the distribution business. As the characteristics of customers within a group will vary then this approach to tariff setting is not fully cost reflective, although the overall distortions may not be large.
- 4.8 In contrast, EHV customers are generally charged for use of the distribution system on a site-specific basis. The main advantage of site-specific charging is

that it enhances cost reflectivity, since customers face charges that reflect the costs they impose on the distribution system. Nevertheless, the present arrangements have several disadvantages. In particular, site-specific charging:

- ◆ is both costly and time-consuming to administer; and
- ◆ there is a lack of transparency about the present arrangements.

4.9 Although site specific charging may be both costly and time consuming to administer for a large number of customers it has been suggested that these costs are offset by the benefits of enhanced cost reflectivity in respect of the small number of large users connected at 22kV and above. Several distribution businesses have also suggested that it is not appropriate to set average charges for these customers since the departure of a single large customer might significantly increase the tariff for the remaining customers.

4.10 Table 4.2 shows the charges that EHV and HV customers pay per unit of electricity. The table demonstrates that some EHV customers appear to be paying more per unit of electricity distributed than HV customers. It has been suggested that many EHV customers have large capacity requirements but use relatively small amounts of electricity. For example, EHV customers may install own generation plant to meet much of their electricity requirements. Nevertheless, they still require access to sufficient network capacity to ensure that they are able to take electricity during periods where the generating plant is unable to produce sufficient electricity. As a result, EHV customers pay fixed components of charges to ensure that sufficient network capacity is available, but take relatively little electricity across the network. This tends to make charges look high if they are calculated in terms of p/kWh unit charges, but would be lower if calculated on the basis of p/kW of capacity.

**TABLE 4.2: COMPARISON OF HV AND EHV DISTRIBUTION CHARGES –2000/01**

Distribution Company	HV charges p/kWh	EHV charges p/kWh
Eastern	0.68	0.43
East Midlands	0.60	0.57
London	0.52	0.79
Manweb	0.52	0.36
Midlands	0.58	0.48
Northern	0.51	0.35
Norweb	0.53	0.69
Seeboard	0.50	0.70
Southern	0.59	0.37
South Wales	0.70	0.33
South Western	0.64	0.41
Yorkshire	0.60	0.40
ScottishPower	0.76	0.16
Hydro-Electric	0.84	0.36
<b>Average</b>	0.61	0.46

Notes:

- 1) Excludes rail traction sites
- 2) Includes a number of high capacity, low volume customers.
- 3) EHV charges include a large number of customers with co-generation facilities.

4.11 Several EHV customers have expressed concern about the lack of transparency in EHV charges. Some have suggested that it is difficult to replicate the calculation of the charges that they incur. Licence condition 8 (Condition 2 of Part VI in Scotland) requires distribution businesses to provide sufficient information to enable users of the distribution system to form a reasonable estimate of the charges they may incur. Views are invited on whether distribution businesses provide sufficient information to EHV customers and whether it is desirable to retain a system of site-specific charges for EHV customers.

4.12 EHV customers are also concerned about the movement in EHV charges since privatisation compared with regulated charges. Distribution revenues per unit attributable to EHV customers have fallen by around 16 per cent in real terms between 1990/91 and 1999/00. In comparison, distribution revenues per unit attributable to other customers have fallen by around 25 per cent in real terms over the same period. In setting the present distribution price controls it was assumed that EHV charges would continue to fall in real terms. Over the period 2000 to 2005 the trend in EHV charges will be carefully monitored to ensure that it is consistent with the assumptions underlying the price control. EHV

customers and their suppliers may also refer certain disputes with distribution businesses in respect of the calculation of charges to Ofgem for determination.

***The balance of fixed and variable elements of charges***

4.13 Distribution use of system charges typically comprise fixed and variable elements. Fixed elements of charges reflect the costs of providing services that are typically customer related, such as the operation and maintenance costs of some connection and metering assets, and customer service costs. Some distribution businesses also recover capacity costs through fixed elements of charges. Variable elements of charges reflect volume-related costs such as the costs of providing, operating and maintaining certain network assets.

4.14 The relative contribution of the fixed and variable elements of use of system tariffs differs across distribution businesses. Table 4.3 shows the charges levied by each distribution company for a typical standard domestic customer on 1 April 2000. The table identifies the fixed and variable components of these charges and the total charge levied for a typical domestic customer with a demand of 3,300kWh per year. The table also demonstrates the variation in the contribution of fixed elements of charges to the overall charge.

**TABLE 4.3: DISTRIBUTION USE OF SYSTEM CHARGES FOR STANDARD DOMESTIC CUSTOMERS – 1 APRIL 2000**

Distribution Company	Fixed charge £/year	Variable charge p/kWh	Total charge £/year	Proportion of fixed charge (%)
Eastern	9.20	1.02	42.86	21
East Midlands	19.71	0.90	49.41	40
London	16.11	1.02	49.77	32
Manweb	16.06	1.32	59.62	27
Midlands	12.50	1.18	51.44	24
Northern	11.56	1.49	60.73	19
Norweb	10.73	1.14	48.35	22
Seeboard	12.92	0.87	41.63	31
Southern	15.15	1.23	55.74	27
South Wales	26.65	1.68	82.09	33
South Western	0.00	1.97	65.01	0
Yorkshire	13.36	1.19	52.63	23
ScottishPower	11.76	1.95	76.11	16
Hydro-Electric	11.86	1.47	60.37	20
<b>Average</b>	13.40	1.32	56.84	24

1) Excludes meter asset provision and operation.

- 4.15 Under the present price controls, Hydro Benefit is transferred to the distribution business of Hydro-Electric and serves to reduce distribution charges in the North of Scotland. The transfer arises from the relatively low cost of Hydro-Electric's hydro power stations. The amount of Hydro Benefit transferred to the distribution business in each available year will depend on the operation of annual adjustment factors. This may result in variations in the level and structure of distribution charges in the North of Scotland relative to the rest of Great Britain.
- 4.16 It has been suggested that differences in network characteristics may result in a different balance of fixed and variable costs across distribution businesses, which in turn may affect tariff structures. However, it is not clear that differences in network characteristics sufficiently explain the variation in balance between fixed and variable components of charges for similar customers located in different regions. It appears that some distribution businesses hypothecate costs differently between elements of charges, in particular those costs that are not clearly defined as customer or volume related costs.
- 4.17 There are also differences in the balance of tariff components between domestic and non-domestic users. Fixed components of charges account for around 24 per cent, on average, of the total charge levied for a typical standard domestic customer. In contrast, fixed components of distribution tariffs account for around 50 per cent, on average, of the total charge levied on non-domestic customers connected at high voltage. For these customers capacity charges are treated as fixed charges, pushing up the proportion of fixed to variable costs.
- 4.18 Views are invited on whether the present balance between fixed and variable elements of charges remains appropriate. In the light of these views, it may be desirable to set out guidelines on how cost items should be treated, for example on the attribution and allocation of costs between fixed and variable components of charges.

### *Embedded generation*

- 4.19 Embedded generation is generating plant connected to the local distribution system rather than to the high voltage transmission networks such as the National Grid system. Embedded generators are generally smaller stations located on industrial sites, combined heat and power plant (CHP), or power stations using renewable fuel sources.
- 4.20 Under the existing trading arrangements, an embedded generator may either sell its output through the wholesale electricity market or via bilateral arrangements. The method by which an embedded generator sells its output will largely depend on whether an embedded generator is subject to central despatch. Those embedded generators subject to central despatch are treated in the same way as generation connected directly to the high voltage transmission network i.e. they must sell their output through the wholesale electricity market and pay transmission network use of system (TNUoS) charges. As such, these generators are subject to broadly similar locational price signals as directly connected generation plant.
- 4.21 There are relatively few embedded generators that sell output through the wholesale electricity market, mostly connected at 132kV or 66kV. Nevertheless, these generators account for a significant proportion of energy exports on to distribution systems. In contrast, there are a significant number of non-pooled embedded generators connected to distribution networks that are not subject to TNUoS charges.
- 4.22 Under NETA all licensed generators will be required to be parties to the Balancing and Settlement Code (BSC) that will incorporate rules for the balancing mechanism and settlement process. The post NETA transmission charging arrangements have been designed to ensure that a generator pays generation TNUoS charges on a broadly similar basis to those arrangements operating prior to the introduction of NETA.
- 4.23 Table 4.4 shows the total number of non-centrally despatched embedded generators connected to distribution networks in Great Britain on 31 March 2000, and the amount of electricity exported to the system during 1999/00. Embedded generators connected at 33kV or below account for around 70 per

cent of the non-pooled energy exported to distribution systems. About 30 per cent of the total 10.0 TWh of non-pooled electricity exported by embedded generators can be attributed to a relatively small number of connected at 66kV and above.

**TABLE 4.4: NON-CENTRALLY DESPATCHED EMBEDDED GENERATION**

<b>Voltage of connection</b>	<b>Number of generators connected</b>	<b>Volume of energy exported (TWh)</b>
132kV	18	1.8
66kV	13	1.2
33kV	123	3.4
22kV	3	0.0
11kV	785	3.3
6kV	2	0.0
LV	508	0.2
Total	1452	10.0

- 4.24 Embedded generation may bring benefits to distribution networks in the form of reduced electrical losses, avoiding or postponing the need for system reinforcement and increasing security of supply. The extent of these benefits will largely depend on the location and pattern of output of each embedded generator. If an embedded generator is situated where demand is low or its output is erratic then it may impose additional costs on the distribution network.
- 4.25 The Government's environmental policies to promote electricity generated from renewable sources may encourage additional generating capacity to be connected to distribution networks. At present a DTI/Ofgem working group on embedded generation issues is considering the incentives for embedded generation.
- 4.26 Embedded generators presently pay the full capital cost of connection to the local distribution system, including the costs of reinforcement across the system. They do not pay use of system charges on their exports. A number of embedded generators have suggested that these arrangements do not reflect the benefits that embedded generators bring to the distribution network.
- 4.27 Generators that are connected to the NGC transmission system pay a combination of shallow connection charges (i.e. connection charges that reflect

the costs of some but not all system reinforcement) and zonal transmission use of system charges. Differentiated use of system charges provide incentives for generators to connect to the transmission system in areas where they may bring benefits to the system. A similar approach might be introduced in respect of embedded generation, with the possibility of embedded generators receiving payments if they are generating in an appropriate zone. Such an approach would require careful consideration, including how implementation of revised arrangements might affect existing embedded generation, how charging zones would be determined, and the timing of any changes.

- 4.28 At present, distribution networks are largely passive systems transporting electricity from the transmission network and embedded generators to customers' premises. In contrast, the transmission network is an actively controlled system with the transmission company managing both network assets and maintaining a national balance between supply and demand. Government environmental policy may encourage an increase in the amount of generating capacity connected to distribution systems. As a consequence, distribution businesses may need to introduce load management systems in order to balance demand and generation requirements. Such requirements could have a significant impact on distribution businesses costs and may have wide-ranging implications for the future development of competition in generation and supply.
- 4.29 It will be necessary to consider the recommendations of the DTI/Ofgem working group in formulating any proposals in respect of charges for embedded generation. Nevertheless, views are invited on whether it would be desirable and or practicable to introduce revised charging arrangements for embedded generators, and in particular, whether a policy of shallow connections and zonal use of system charges would be appropriate.

### ***Energy efficiency***

- 4.30 Electricity is lost during the transfer from exit points on the transmission system to customers' premises. This is largely due to heating of distribution transformers, underground cables, and overhead wires. As a consequence of these losses, additional units of electricity must be generated and transported

over the distribution system to ensure that the demands of customers are met. This will have a number of adverse effects including the need to increase the generation of electricity from fossil fuels, which is a major contributor to greenhouse gas emissions in Great Britain.

- 4.31 The distribution price controls incentivise distribution businesses to reduce electrical losses on their systems. Table 4.5 sets out the average level of electrical losses for each distribution company. It shows that the average level of losses fell from 7.6 per cent at privatisation to 6.7 per cent in 1995/96. Nevertheless, losses have remained relatively stable at around 6.9 per cent since 1996/97.

**TABLE 4.5: DISTRIBUTION LOSSES FOR LV AND HV CUSTOMERS**

Distribution Company	1990/91 (%)	1995/96 (%)	1996/97 (%)	1997/98 (%)	1998/99 (%)	1999/00 (%)
Eastern	7.0	6.9	7.1	7.0	7.1	7.3
East Midlands	6.6	6.1	6.1	6.1	6.1	6.1
London	7.8	6.7	7.1	6.8	7.1	6.5
Manweb	9.8	8.8	8.8	9.0	9.0	8.9
Midlands	6.2	5.5	5.6	5.5	5.4	5.4
Northern	7.5	6.8	6.9	6.7	6.7	6.7
Norweb	7.1	4.8	5.0	5.7	6.0	5.9
Seeboard	7.9	7.1	7.6	7.7	7.6	7.4
Southern	7.1	7.2	7.2	7.2	7.2	7.2
South Wales	8.9	6.7	8.0	6.9	6.1	7.7
South Western	8.6	7.2	7.9	7.3	7.5	7.3
Yorkshire	6.3	6.5	6.5	6.5	6.6	6.7
ScottishPower	8.5	6.7	7.2	7.2	7.2	7.2
Hydro-Electric	9.4	9.0	9.0	9.1	9.0	9.1
<b>Average</b>	7.6	6.7	6.9	6.8	6.9	6.9

- 4.32 Electrical losses are typically highest when electricity is transported at times of peak load. The distance that electricity is transported is also a major factor determining losses on the system. Distribution businesses can reduce these losses by installing lower-loss equipment, or by modifying the configuration of their network. The charges levied by distribution businesses can reflect the time and distance the electricity is transported.
- 4.33 Several distribution businesses have adopted pricing structures that may encourage efficient use of energy. In setting charges for larger users many distribution businesses also distinguish between the costs imposed by summer

and winter load. These structures may encourage customers to take supply during periods when electrical losses are lower.

- 4.34 The power factor at each connection point on a distribution system may influence the level of distribution losses. Power factors describe the size of the power flow across the distribution system (measured in kVA) necessary to ensure that a customer's demands (measured in kW) are met. A customer with a poor power factor requires relatively large power flow per unit of demand compared with a customer with a high power factor. If power factors are improved and power flows reduced then network losses should fall.
- 4.35 Several distribution businesses adopt kVA metering to measure the input power flows of their larger customers. A charge for available capacity is levied to reflect the maximum power requirement of these customers measured in kVA. Seven distribution businesses also levy explicit charges for the excess reactive power associated with poor power factors. These charges are intended to reflect the additional costs that customers with poor power factors impose on the distribution system. It has been suggested that reactive power charges provide incentives to encourage customers to improve their power factor, possibly by installing in power factor correction equipment.
- 4.36 Several interested parties have said that distribution businesses should be required to structure their charges in such ways as to strengthen the incentives on larger customers to improve their power factors and so increase energy efficiency. Nevertheless, the effectiveness of any tariff structure in providing the correct signals to reduce network losses will largely depend on how suppliers reflect these price signals within charges to end-users.
- 4.37 Distribution businesses publish line loss adjustment factors to reflect the contribution of each customer group to system losses. These line loss adjustment factors are used in the calculation of the cost of wholesale electricity purchases. There is some concern that published loss adjustment factors do not reflect the actual contributions of customers to system losses. For example, it appears that the costs of abstraction or theft are smeared across all suppliers through line loss adjustment factors, weakening the incentives on suppliers and distribution businesses to take action to reduce theft. It is for consideration

whether published loss adjustment factors have been derived appropriately or whether alternative arrangements would be appropriate.

- 4.38 Views are invited on whether distribution businesses have taken appropriate steps to structure use of system charges to encourage the efficient use of energy.

***Boundary between connection and use of system charges***

- 4.39 The connection charge policies adopted by distribution businesses may influence the boundary between connection and use of system charges. In turn, this may influence the level and structure of use of system charges.

- 4.40 Distribution businesses can adopt one of three broad approaches in deriving charges for connecting an embedded generator or a customer's premises to the distribution system. The first approach involves an estimate of the total costs that will be incurred as a result of connecting new load to the system, including the costs of network reinforcement at higher voltage levels. This is often described as a deep connection charge policy. The second approach involves an estimate of the cost of the connection assets, excluding the costs of network reinforcement at higher voltage levels. This is often termed a shallow connection charge policy. The third approach involves an estimate of the cost of those assets required to connect a customer to the voltage of connection, excluding the costs of extension and reinforcement to the system. Consequently, this type of connection mainly reflects the cost of providing the service line or cable required to connect the customer to a distribution system. This is often termed a local connections policy.

- 4.41 Under each of these arrangements, use of system charges will recover the residual costs associated with the provision and reinforcement of network assets. For instance, the costs of upstream reinforcement required to accommodate new load is reflected in use of system charges where a distribution company adopts a shallow or local connections policy. In contrast, these costs are reflected in connection charges where a distribution company adopts a deep connection policy. Use of system charges are typically higher where a company adopts a shallow connection policy. Conversely, connection charges are higher where a company adopts a deep connection policy.

- 4.42 Distribution businesses operate a relatively shallow connections policy in respect of connections for demand customers. In August 1994, OFFER set out proposals in respect of the appropriate method for deriving connection charges for demand customers as part of the distribution price control review. OFFER proposed that connection charges should not take account of reinforcement costs more than one voltage level above the voltage of connection. Reinforcement costs beyond this voltage level should be reflected in use of system charges. OFFER also proposed that demand customers should not normally be charged for network reinforcement if the increased load requirement does not exceed 25 per cent of the existing capacity at the point of connection to the distribution system. Distribution businesses operate a deep connections policy in respect of connections for embedded generators.
- 4.43 In calculating connection charges, distribution businesses sometimes make allowances for the proportion of connection costs that can be deferred and recovered through use of system tariffs. These allowances are often described as tariff support allowances. The application of tariff support allowances tends to make the boundary between connection and use of system charges more complex and less transparent.
- 4.44 Distribution businesses also make up-front capitalised operating and maintenance (O&M) charges as part of their connection charges. As with tariff support allowances O&M charges tend to complicate and make the calculation of connection charges less transparent.
- 4.45 Distribution businesses operate different policies in respect of tariff support allowances and O&M charges, which may explain some of the variation in the level and structure of distribution charges across distribution businesses. Table 4.6 summarises the policies adopted by each distribution business in respect of tariff support and O&M charges.

**TABLE 4.6: TARIFF SUPPORT ALLOWANCES AND O&M POLICY**

Distribution Company	Tariff Support Allowance	O&M policy
<b>Eastern</b>	Allowances calculated with reference to the estimated annual usage of the type of premises.	Capitalised O&M charge is applied to the connection charge where the full costs of O&M are not expected to be recovered through DUoS.
<b>East Midlands</b>	Fixed allowance applied to connection charges based on the type of premises.	Connection charge reflects the capitalised cost of O&M over the life of the asset.
<b>London</b>	Domestic – fixed allowance per dwelling; Non-domestic – fixed allowance per customer, plus additional £/kVA allowance for connections > 70kVA.	Connection charge reflects the capitalised cost of O&M.
<b>Manweb</b>	Domestic and quarterly business customers – fixed allowance per premises; Monthly business customers - £/kVA allowances.	Connection charge reflects the capitalised cost of O&M.
<b>Midlands</b>	Domestic and quarterly business customers – allowance per premises; Monthly business customers – allowance per customer plus £/kVA allowances.	Connection charge reflects the capitalised cost of O&M. O&M is 22 per cent of the initial asset value for assets with a life of 20 yrs and 27 per cent for assets of 40 yrs.
<b>Northern</b>	Domestic premises – allowance per premises, plus £/MWh allowance; Business premises – allowance per customer plus £/kVA allowances.	Connection charge reflects the capitalised cost of O&M. O&M is 0.98 per cent per annum expressed as a percentage of the initial asset value.
<b>Norweb</b>	Domestic customers – allowance per premises; Business customers – allowance per £/kVA.	Connection charge reflects the capitalised cost of O&M.
<b>Seeboard</b>	Connections up to 40kVA – allowance per property; Connections 40kVA to 1MVA – allowance per £/kVA.	Connection charge reflects the capitalised cost of O&M. O&M is 25 per cent of the initial assets value.
<b>Southern</b>	Domestic and business connections up to 72kVA – allowance per property; Connections > 72kVA – allowance per kVA.	Connection charge reflects the capitalised cost of O&M, expressed as a proportion of the initial asset value.
<b>South Wales</b>	Domestic and quarterly business connections – allowance per property; Monthly business customers – allowance per customer, plus allowance per kVA.	Connection charge reflects the capitalised cost of O&M. O&M is 1.7 per cent per annum, expressed as a percentage of the initial asset value.
<b>South Western</b>	Quarterly billed – fixed allowances given for types of work; Non-domestic – fixed allowance per customer, plus additional £/kVA allowance for connections	Connection charge reflects the capitalised cost of O&M. O&M is 2.25 per cent per annum, expressed as a percentage of the initial asset value.
<b>Yorkshire</b>	Domestic – fixed allowances given for types of connection equipment used;	Capitalised O&M charge is applied to the connection charge where the full costs of O&M are not expected to be recovered through DUoS.
<b>ScottishPower</b>	Domestic and quarterly business customers – fixed allowance per premises; Monthly business customers - £/kVA allowances.	Connection charge reflects the capitalised cost of O&M.

Distribution Company	Tariff Support Allowance	O&M policy
Hydro-Electric	Domestic and business connections up to 72kVA – allowance per property; Connections > 72kVA – allowance per kVA.	Connection charge reflects the capitalised cost of O&M.

Source: PES connection charge statements

- 4.46 Where a distribution business adopts a system of generalised tariffs to reflect the broad costs that a customer of a given type will typically impose on the distribution system, price signals to reflect costs differences by location may be muted. Under these circumstances, connection charges may have an important role in providing appropriate price signals to customers in respect of network location. For example, deep connection charges may provide signals to developers and new customers by reflecting all the specific costs they impose on the distribution system at the time of connection, including the costs of system reinforcement.
- 4.47 A clearly defined boundary between connection and use of system charges will encourage competition in the provision of connections and reduce the number of connection charge disputes that occur in respect of the allocation of assets. It has been suggested that the existing boundary between connection and the system is relatively opaque. As a consequence, there are a relatively large number of disputes in respect of the allocation of costs between the customer and other network users. Several customers have indicated that it is not clear that distribution businesses are allocating costs appropriately, and thus they are concerned that some costs may be double counted. It is important that distribution businesses provide sufficient information to assure customers that charges have been calculated appropriately.
- 4.48 Significant modification to the boundary between connections and use of system charges would raise a number of concerns in respect of the treatment of existing customers and the impact on distribution price control revenues. Distribution price control revenues reflect the capital expenditure incurred by an efficient distribution company, net of connection charge receipts. Making significant changes to the boundary between connection and use of system charges could create inconsistencies with the assumptions underlying the price control. It would therefore be important to consider the timing of any changes or whether

it would be appropriate to put in place transitional arrangements until the next price control review.

- 4.49 Views are invited on whether the present boundary between connection and use of system charges is appropriate and whether it might be appropriate to abolish tariff support allowances and O&M charges. Views are also invited on whether it might be desirable for distribution businesses to adopt a consistent boundary between connection and use of system. Shallow connections charge would help encourage the development of competition in the provision of connections.

### ***Other issues***

- 4.50 Distribution businesses have a duty to facilitate competition in the supply and generation of electricity. Several suppliers have expressed concern that distribution businesses do not provide information in a suitable form to facilitate ease of entry into the market, particularly with respect to the statement of charges published by distribution businesses.
- 4.51 Distribution businesses are required to publish a statement of distribution charges, that provides sufficient information to enable suppliers to make a reasonable estimate of the charges that they would incur. An explanation of the principles upon which charges are derived is also set out in the statement. Licence condition 8 requires that the statements be published in a form approved by Ofgem. In Scotland, Licence condition 2 of Part VI requires that the content of the statement must also be approved by Ofgem.
- 4.52 Several suppliers have expressed concern that the form of the charging statements published by distribution businesses are not consistent. It has been suggested that this lack of consistency across businesses makes it difficult to derive reasonable estimates of charges. It is for consideration whether it would be desirable for distribution businesses to provide charging statements in a more consistent form.

## *Conclusion*

4.53 Ofgem welcomes view on any aspect of the issues raised in this chapter and in particular on:

- ◆ whether the differences in charges for domestic and non-domestic customers reflect the appropriate balance of costs;
- ◆ whether distribution businesses provide sufficient information to EHV customers and whether it is desirable to retain site-specific charges for EHV customers;
- ◆ whether the present balance between fixed and variable elements of charges remains appropriate, in particular the suggestion that it may be desirable to set out guidelines on how cost items should be treated, for example on the attribution and allocation of costs between fixed and variable components of charges;
- ◆ the suggestion that distribution business should adopt a policy of shallow connection and zonal use of system charges for embedded generation;
- ◆ whether the existing structure of charges provides appropriate incentives to encourage efficient use of energy, particularly whether distribution businesses should levy extra charges for low power factors;
- ◆ whether the boundary between connection and use of system charges is appropriate, in particular the suggestion that tariff support allowances and capitalised O&M charges should be abolished; and
- ◆ the steps that might be taken to improve the information provided by distribution businesses in respect of use of system charges, in particular whether it is appropriate to introduce a more consistent form of charging statement.

## 5. Distribution networks and NETA

### *Introduction*

- 5.1 Ofgem's June 2000 consultation paper Distribution Networks and NETA identified the key issues in respect of the interaction between distribution networks and NETA. It built on the material set out in the October 1999<sup>3</sup>, December 1999<sup>4</sup> and April 2000<sup>5</sup> NETA consultation and conclusion papers. A summary of responses to the June consultation paper can be found in appendix 1. This chapter sets out Ofgem's further thinking on these issues and invites views on how these matters can be best taken forward.
- 5.2 A distribution constraint or failure can result in an embedded generator having to reduce output and or an interruption in supply to a customer. The introduction of NETA will increase the transparency of costs arising from these interruptions and allow imbalance charges to be attributed to generators and suppliers.
- 5.3 The June consultation paper invited views on the following:
- ◆ a suggestion that it would not be appropriate for distribution businesses to bear the direct costs of imbalances arising out of distribution constraints and failures;
  - ◆ whether in light of changes in the attribution of imbalance costs arising out of NETA it might be appropriate to reconsider the network design standards;
  - ◆ whether it might be appropriate to introduce new standards and penalty payments in respect of the quality of service received by embedded generators and suppliers;
  - ◆ the advantages and disadvantages for enhancing information requirements and incentives on distribution businesses;

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<sup>3</sup> October 1999 Ofgem DTI Conclusions: New Electricity Trading Arrangements.

<sup>4</sup> December 1999 Ofgem Consultation: NGC SO Incentives, Transmission Access & Losses Under NETA.

<sup>5</sup> April 2000 Ofgem Consultation: NGC SO under NETA, Transitional Arrangements.

- ◆ whether there is scope for the development of risk hedging services;
- ◆ the implications for the distribution price controls; and
- ◆ whether in the light of uncertainties about the level of imbalance costs and other matters suggest that it would be more appropriate to delay consideration of any of these issues until better information is available.

5.4 In light of the responses to the June paper, Ofgem has developed further thoughts on these issues, which are outlined below. Nevertheless, it will be necessary to consider the views and recommendations of the DTI/Ofgem working group on embedded generation issues before formulating final proposals.

***The direct costs of imbalances***

5.5 An embedded generator and or the customer's supplier may incur imbalance charges under NETA as a result of distribution network constraints and or failures. Generators, suppliers and customers may also incur additional economic or financial losses as a result of an interruption.

*The June consultation paper*

5.6 The paper suggested that distribution businesses have no direct control over the economic and financial costs arising from network constraints or failures. There are also a number of options available to embedded generators and suppliers to reduce exposure to these costs.

5.7 As a consequence of these factors, the paper suggested that it would not be appropriate for distribution businesses to bear the direct costs of imbalances arising out of distribution constraints and failures.

*Respondents' views*

5.8 Some respondents supported the view that distribution businesses should not bear the direct costs of imbalance charges. Others suggested that distribution businesses should be liable for those costs arising from failures of the distribution system. Of these, one respondent suggested that network operators should be incentivised to minimise the number of incidents, while a small

number of respondents noted that if a network operator bears these costs then this may incentivise action against third party damage, a major cause of constraints and failures.

- 5.9 The June paper noted that there are compensation arrangements in respect of network interruptions for domestic and non-domestic tariff customers. These are set out in the form of Guaranteed Standards of Performance. Several respondents noted that these arrangements do not apply to network incidents involving large users, and it was suggested that new arrangements should be introduced for large users. Two respondents said that these new arrangements should provide substantial financial penalties on distribution businesses to reflect the economic losses associated with network constraints and failures.

#### *Ofgem's Views*

- 5.10 It is important that an appropriate balance of incentives is achieved between distribution businesses, embedded generators, suppliers and their customers to encourage appropriate responses in respect of network interruptions.
- 5.11 At present, there are Standards of Performance, targets for reducing customer minutes lost and targets for reducing the number of interruptions, that provide incentives to restore supplies to demand customers in a robust and timely fashion. Ofgem is seeking to strengthen these incentives through the IIP.
- 5.12 In respect of the wider issue of economic and financial loss, distribution businesses have no direct control over the economic and financial costs associated with network failures. In contrast, embedded generators, suppliers, and customers may be able to take steps to minimise their financial losses. Given these factors and the development of the incentive framework described above, it is not appropriate that distribution businesses incur these wider costs.

#### ***Revisions to network design standards***

- 5.13 The minimum network design standards that distribution businesses are required to meet in operating their networks are summarised in paragraph 2.9. These standards have a significant influence on quality of service.

*The June consultation paper*

- 5.14 The paper asked whether in light of the changes in the attribution of imbalance costs arising out of NETA it would be appropriate to reconsider the existing network design standards. The present arrangements specify that for large demands, the network has to be designed to continue to provide electricity to customers after a single fault or failure of network equipment. Whereas, for groups of customers with demands below 1 MW a fault or failure can interrupt supplies and there is only a requirement to restore supply following repair.

*Respondents' views*

- 5.15 A small number of respondents indicated that it might be desirable to adopt revised network design standards. It was suggested that revised arrangements should be updated to take account of increasing embedded generation.
- 5.16 Several respondents noted that network design standards reflect the trade off between cost and security. As a consequence, there was a general level of support for continuing with the present arrangements with the suggestion that a cost-benefit analysis should justify any significant revisions to the existing standards.
- 5.17 Some respondents noted that the DTI/Ofgem working group on embedded generation issues is presently considering the issue of revised network design standards. It was also suggested that any revised arrangements should wait until the next distribution price control review to minimise the uncertainty regarding cost recovery.

*Ofgem's Views*

- 5.18 The existing network planning standards were introduced before privatisation, when there was little expectation of widespread growth of embedded generation. The Ofgem/DTI working group on embedded generation issues is presently considering these matters. It will be necessary to consider the findings of the working group before making any final proposals. Nevertheless, revised standards would require careful consideration, including the timing of any investment to comply with the revised standards and the process by which additional capital and operating expenditure may be recovered from customers.

## *Compensation Payments*

- 5.19 Ofgem has set Guaranteed and Overall Standards of Performance to encourage distribution businesses to maintain and improve levels of service for customers. Guaranteed Standards of Performance determine service levels that must be met in each individual case. If a company fails to provide the level of service specified, it must make a fixed payment to the customer concerned. Overall Standards apply to areas where it is not appropriate or feasible to give individual guarantees but where it is reasonable for customers, in general, to expect a minimum level of service.
- 5.20 Overall Standards (1a and 1b) require distribution businesses to restore a supplies to minimum percentage of customers within 3 and 18 hours respectively. Guaranteed Standard GS2 specifies that payments of £50 and £100 are automatically available for domestic and non-domestic tariff customers respectively if the distribution business fails to restore supplies within 18 hours of an interruption.

### *The June consultation paper*

- 5.21 The paper considered whether the present incentive framework should be extended to include interruptions involving embedded generators and suppliers. It invited views on whether it is desirable to introduce compensation arrangements for embedded generators and suppliers and at what level, if any, these should be set. In developing proposals on these matters, it would be important to ensure that the costs of any new arrangements are proportionate to the benefits and that incentives on embedded generators and suppliers for efficient operation are not distorted.

### *Respondents' views*

- 5.22 Several respondents suggested that compensation payments should be reflective of the level of security of the connection requested by the customer. These respondents said that certain embedded generators choose low cost and low security connections and consequently it would be inappropriate to apply universal compensation payments to all embedded generators. Several respondents expressed concern that if compensation payments were significant

this might create perverse incentives to restore supply for a small number of network users and distort overall incentives.

- 5.23 A small number of respondents suggested that the compensation arrangements should be proportionate to the distribution use of system charges incurred by each user. Other respondents said that compensation should be set at a level sufficient to cover economic or financial loss incurred as a result of a network failure.

#### *Ofgem's Views*

- 5.24 Some of the comments made in response to the June consultation paper appear to relate to wider concerns respondents have in relation to compensation payments following an interruption in distribution network availability, rather than specific concerns relating to the introduction of NETA. These wider matters are outside of the scope of this review.
- 5.25 If fixed compensation payments for distribution interruptions were to be available to embedded generators or suppliers then these would need to be substantially higher than the existing payments to demand customers to make a significant impact on the incentives faced by a distribution business or the economics of an embedded generation station or supply business. It would not be appropriate to reward embedded generators that have chosen a connection which provides for a low security of supply. At this time it is not clear that the changes arising out of NETA justify new compensation payments for suppliers. Therefore it will not be appropriate to introduce new compensation arrangements at present, although it may be appropriate to reconsider these matters if more systematic information becomes available on connection arrangements and quality of service to embedded generators and suppliers, or in the light of wider considerations and the development of the IIP.

#### ***Enhancing information***

- 5.26 Each distribution business is presently required to monitor the number, duration and cause of interruptions in supply experienced by its demand customers. Since privatisation, improvements in outage co-ordination between distribution

businesses and embedded generators have significantly reduced the costs associated with distribution network constraints.

*The June consultation paper*

- 5.27 The paper asked whether the outage co-ordination arrangements already in place could be enhanced and whether the present requirements of monitoring interruptions should be extended to embedded generators.

*Respondents' views*

- 5.28 The majority of respondents supported the enhancement of information providing requirements placed on distribution businesses. However, support from distribution businesses was qualified by either the suggestion that an additional allowance for developing monitoring systems would be required, or that such information should be meaningful and readily available from existing systems and processes. Several respondents also noted that the IIP will enhance information and that Ofgem should wait until the impact of this project is known before suggesting additional requirements.

*Ofgem's Views*

- 5.29 Extending the monitoring of interruptions to embedded generators will allow for targets to be established, incentives improved and a better quality of service for embedded generators. Given the relatively small number of embedded generators it is not clear that a requirement to monitor their quality of service would add significantly to distribution costs. In the light of this, it is intended to require distribution businesses to provide information on the frequency and duration of interruptions experienced by embedded generators. It is also for consideration whether embedded generators and suppliers receive adequate notice of planned interruptions and whether there is scope for ensuring all distribution businesses adopt best practice with respect to providing information on interruptions.

### ***The development of risk hedging services***

#### *The June consultation paper*

- 5.30 The paper asked whether distribution businesses should be encouraged or required to offer risk hedging services to embedded generators and or suppliers. The paper suggested that such arrangements might involve enhanced compensation payments for interruptions in network availability to users willing to pay appropriate insurance or additional distribution charges.

#### *Respondents' views*

- 5.31 Many respondents supported the development of risk hedging services. However, the majority of these suggested that the market should provide insurance against distribution constraints and failures. It was suggested that it is inappropriate for distribution businesses to offer risk hedging services over events that they may influence. Instead of requiring risk hedging services Ofgem should focus its attentions on ensuring that a distribution business faces appropriate overall incentives in operating and maintaining its network.

#### *Ofgem's View*

- 5.32 The views and arguments set out above appear to have some force and so the development and provision of risk hedging services will be left to commercial providers of insurance.

### ***The implications for the distribution price controls***

- 5.33 The approach to the interaction between distribution networks and NETA set out above should not impose significant additional costs on distribution businesses in the short-term.

#### *The June consultation paper*

- 5.34 The paper asked for respondents to comment on the possible implications for the distribution price controls with regard to the suggestions made in the document.

### *Respondents' views*

- 5.35 Of the responses received, a large proportion noted that the existing distribution price controls make no allowances for the costs associated with NETA. In light of this, it was suggested that any additional costs arising from revised incentives should be excluded from the controls. Furthermore, where those costs have a material impact on the distribution business it was suggested that the price controls should be re-opened to revisit the assumptions on costs. This would probably lead to an increase in charges for both generators and suppliers in line with the increased costs.

### *Ofgem's views*

- 5.36 As noted above, distribution businesses should not bear the direct costs of imbalances. Nevertheless, Ofgem recognises that there are issues (such as possible changes to planning standards deriving from the work of the DTI/Ofgem working group on embedded generation) that may lead to increases in distribution business costs in the future. Therefore, it may be necessary to examine implications for the price controls in light of these factors.

### ***Conclusions***

- 5.37 Views are invited on any aspect of the issues raised in this chapter and in particular on:
- ◆ the proposal that distribution businesses should improve information and be required to monitor the number and duration of interruptions to embedded generators;
  - ◆ the proposal that distribution businesses should not bear the direct costs of imbalances;
  - ◆ the suggestion that at present it would also not be appropriate to introduce compensation payments for embedded generators and suppliers; and
  - ◆ the proposal in paragraph 5.32 that risk-hedging services should be left to commercial providers of such services.

## 6. Consultation process

### *Introduction*

- 6.1 This chapter sets out the timetable for the review of the structure of electricity distribution charges. The timetable is broadly as follows:

December 2000	Publish initial consultation paper
Early 2001	Public workshop
Spring 2001	Initial Proposals document
Summer 2001	Proposals document
October 2001 to April 2002	Implementation phase

- 6.2 The public workshop in early 2001 will provide a forum to discuss the issues set out in this document and those identified by respondents. Those wishing to attend the workshop should complete the attached form and return it by 15 January 2001. This information will be used to provide further details in respect of the venue and format of the event to those interested in attending closer to the time.
- 6.3 There may be a large number of interested parties wishing to attend and in light of this, it is proposed to limit the numbers of representatives to two per company or organisation. Some groups of companies may have more than one business interest that should be represented. A group of companies with more than one relevant business (for example distribution and supply) is limited to one additional representative per additional business.

**Contact form**

Name:	
Position:	
Business:	
Address:	
Telephone number:	
Fax number:	
E-mail address:	

Please send your details to Colin Green or Richard Clay at the address indicated in chapter 1, or fax to 020 7901 7478 by 15 January 2001.

# Appendix 1 Summary of responses to the Distribution Networks and NETA consultation paper (June 2000)

## Introduction

- 1.1 There were 26 responses to the June 2000 Distribution Networks and NETA consultation paper from a range of interested parties – Public Electricity Suppliers, NGC, generators, suppliers, customers and customer representatives.

## Costs of imbalances arising from constraints and failures

- 1.2 The June consultation paper suggested that distribution businesses should not bear the direct costs of imbalances arising from distribution constraints and failures, and invited comments on this view.
- 1.3 All of the PESs and a number of non-PES respondents supported this position. One PES commented that distribution businesses should not be made liable for events outside of their control and indicated that generators and suppliers would be able to manage risks. One PES said that exposing distribution businesses to the cost and risks of imbalances would undermine the existing distribution price controls.
- 1.4 Five non-PES respondents commented that distribution businesses should bear the costs of imbalances. Of these, one respondent suggested that network operators should be incentivised to minimise incidents, while two respondents noted that bearing the costs may encourage action to minimise the disruption from third party damage.
- 1.5 Two respondents suggested distribution businesses have some control over interruptions and are able to manage the risks of distribution failures, therefore they should bear some of the imbalance costs. One respondent added that generators have no control over interruptions and so should not bear the associated costs.
- 1.6 One non-PES respondent supported the move toward performance related regulation for distribution businesses. It said that one clear way to provide

performance incentives is to ensure that distributors incur the economic costs of failure of the system.

- 1.7 One PES stated that distribution businesses are unaware and have no influence over any consequential costs arising from constraints or failures. It is therefore inappropriate to pass these on to distribution businesses.

#### **Proposal to delay consideration of issues until better information is available**

- 1.8 The June consultation paper invited views on whether the uncertainties about the level of imbalance costs and other matters suggested that it would be more appropriate to delay consideration of these issues until better information is available.
- 1.9 Most PESs agreed with this suggestion. Of these, two PESs suggested waiting until after the findings of the Ofgem/DTI embedded generation working group. Three PES respondents and two non-PES respondents suggested evidence of performance under NETA should be considered before any revisions to the present arrangements are made.
- 1.10 One PES and a number of non-PES respondents suggested that there should be no delay in the consideration of imbalance costs. One respondent suggested that imbalance costs will remain uncertain and the general principles can be debated independently of the magnitude of the costs.
- 1.11 Two respondents argued for interim measures to be put in place prior to the introduction of NETA and said that a fully worked solution may require changes to use of system and connection agreements.

#### **Revised network design standards**

- 1.12 Two PES and four non-PES respondents supported the reconsideration of network design standards. Of these, one respondent commented that any change to the reliability of supply should reflect the agreements in place with generators and the right to claim compensation depending upon the chosen security level. One respondent said that design standards should be updated to account for embedded generation. Another respondent stated that a degree of change might be appropriate with the introduction of NETA.

- 1.13 A number of respondents noted that network design standards are to some extent a trade off between cost and security. Of these, there was a general level of support for continuing with the present arrangements. It was also noted that a cost-benefit analysis should be undertaken to justify any change.
- 1.14 A number of respondents indicated that the DTI/Ofgem embedded generation working group is presently considering the issue of revised network design standards. One respondent noted that a cost-benefit analysis needs to be undertaken before any changes are implemented. Three respondents suggested that any revisions should wait until after the next distribution price control review.
- 1.15 One non-PES suggested there was little reason to justify changes to primary equipment design standards. However, secondary equipment is often identified as the cause of interruptions and may therefore require a revised approach.

#### **Improving information**

- 1.16 The June consultation paper invited views about whether distribution businesses might improve outage co-ordination and provide information on the number and duration of interruptions experienced by embedded generators.
- 1.17 Two PES and several non-PES respondents supported the provision of enhanced information on interruptions. Of these, one PES indicated that such information would need to be meaningful and readily available from existing systems and processes. A small number of respondents said that the provision of further information would not be necessary.
- 1.18 Several respondents noted that the IIP will enhance information and incentives and therefore Ofgem should not impose further incentives on distribution businesses until the impact of IIP is known. One respondent said that exposure to imbalance costs would incentivise the undertaking of necessary investment and maintenance work to networks, establishing a link with IIP. Another respondent indicated that it is worth considering how the IIP can incentivise network operators to connect particular types of generation.

- 1.19 One non-PES respondent said that the June consultation paper should have discussed the impact of transient interruptions. Two further respondents noted that enhancements in tackling transients will be made by the IIP.
- 1.20 One respondent indicated that the proposed improvements in outage planning were in the main aimed at centrally despatched generating plants and was dubious whether these could be adopted for smaller embedded generators.

### **New Standards and Penalty Payments**

- 1.21 A number of PES and non-PES respondents said that compensation payments, in the form of Guaranteed and Overall Standards of Performance, should be reflective of the level of security of the connection. One PES was concerned that liabilities for constraints might create perverse incentives to restore supply for a small number of network users. Two PES respondents said that this area of consultation should be within the remit of the Ofgem/DTI embedded generation working group.
- 1.22 A number of respondents have expressed concern at the possible extension of compensation payments to embedded generators. Many respondents noted that embedded generators accept lower levels of security by opting for low cost connections. Two PESs noted that any compensation payments should be calculated per exit point on the system.
- 1.23 One non-PES respondent did not support the view that additional standards are required in relation to network failures for embedded generators. One respondent noted that Guaranteed Standard compensation payments would weaken incentives, and would neither be cost reflective nor have a bearing on imbalance costs.
- 1.24 Two non-PES respondents commented that compensation payments should reflect DUoS charges levied. One respondent argued that large users and generators should be entitled to compensation of around 50 per cent of the annual DUoS bill. One respondent argued that compensation payments to larger customers should form part of the price control.
- 1.25 One non-PES respondent indicated that the proposals do not adequately address the issues, suggesting that a payment of £4-5 million for an embedded generator

is in line with the current £50 payments to domestic customers who experience an interruption in excess of 18 hours.

### **Development of Risk-Hedging services**

- 1.26 The June consultation paper asked whether distribution businesses should be encouraged or required to offer a risk-hedging service to embedded generators and suppliers.
- 1.27 Most PES respondents supported the development of risk-hedging services. Nevertheless, most respondents suggested that such services should be provided by the market, and not by distribution businesses.
- 1.28 Most non-PES respondents felt it inappropriate for distribution businesses to provide risk-hedging services. Of these, three respondents stated that they would be wary of distribution businesses offering insurance for events over which they have influence.
- 1.29 One non-PES respondent indicated that the notion of providing risk-hedging services appears inconsistent with the concept of a low risk business. A non-PES respondent noted that the development of enhanced compensation arrangements could be developed as a discretionary and unlicensed activity.
- 1.30 One respondent stated that where distribution businesses have no influence over events, it is important they be allowed, but not compelled, to offer risk-hedging services. Two other respondents agreed that distribution businesses are best able to arrange insurance services.

### **The implications for the distribution price controls**

- 1.31 The June consultation paper invited comments in respect of the impact of these issues on the price controls.
- 1.32 Several PES respondents suggested that any revenues from risk management services should be treated either as excluded service revenue or, in respect of those costs arising from additional GS payments, treated as cost pass through items. Many respondents also noted that the price control makes no allowance for such additional costs and therefore would need revisiting. One PES

indicated that this is undesirable. Another suggested that such issues could be considered at the next price control review. One non-PES indicated that despite costs not being allowed within the price control, distributors should not be rewarded for failures to meet accepted standards of performance.

- 1.33 One PES indicated that if distribution businesses become liable for compensation payments, both generators and suppliers should face higher charges. This concern was echoed by a non-PES respondent who suggested that it is important to understand the impact this would have on particular customer groups.

#### **Other comments**

- 1.34 Several respondents indicated that it would be beneficial for Ofgem to clarify the timetable for the consultation process, and the likely interaction with other Ofgem initiatives, such as IIP, the DTI/Ofgem embedded generation working group and the arrangements for transmission access.
- 1.35 Both PES and non-PES respondents highlighted failures of networks may be due to the actions of third parties. However, distribution businesses should be incentivised to seek the appropriate redress as it should be possible to identify the third parties concerned.
- 1.36 One PES indicated that generators take commercial judgements on the cost of network connections and balance these against the security provided by the connection. It said that introducing constraint payments might provide perverse incentives for generators to choose low cost, low security connections. A non-PES respondent made similar suggestions and indicated that generators should accept a higher level of risk in respect of loss of access to the network should they opt for lower cost connections.

## List of Respondents

East Midlands Electricity  
Midlands Electricity (GPU Power UK)  
South Wales Electricity (Infralec)  
London Electricity (LPN)  
Northern Electric (NEDL)  
NORWEB  
ScottishPower (including Manweb)  
Scottish and Southern Energy  
Seeboard  
Eastern Electricity (TXU Europe Ltd)  
South Western Electricity (Western Power Distribution)  
Yorkshire Electricity  
Distribution Commercial Group

British Gas Trading  
Innogy  
Yorkshire Electricity Supply  
AEP  
British Energy  
Slough Heat and Power  
The Confederation of Renewable Energy Associations  
BOC  
The Boots Company  
The Major Energy Users Council  
The Utility Buyer' Forum  
Electricity Association  
NGC

## Appendix 2 Eastern Electricity (TXU Europe Distribution)

2.1 This paper outlines the charging and cost allocation methodology employed by TXU Europe Distribution. It is produced in accordance with Colin Green's letter of 14th September "Review of the Structure of Electricity Distribution Charges: Information Request". As such, it aims to answer the specific questions presented in that request, avoiding a potentially lengthy analysis of the detail of this process. Additional information can be obtained from our Condition 8 Publications.

**Describe to what extent the methods and principle adopted differ from those set out in the seminal paper by Boley and Fowler**

2.2 Whilst the approach we adopt is broadly similar to the work of Boley and Fowler, the paper was written prior to privatisation and would not recognise the form of regulation under which we operate. The method used has evolved over that time, although it came from a similar theoretical start point.

**Identify the cost drivers captured within in use of system charges**

2.3 Cost drivers are split into 3 categories, customer driven, volume driven and supplier driven.

2.4 Customer driven costs include the costs of the MPAS system, the UoS billing systems, other DMSCR costs, use of current transformer and an annuity on the service cable. These are recovered through UoS Standing Charges. Differences in standing charges reflect the different costs for a customer type. For example, the service cable cost differs between customers connected at single-phase or multi-phase. Also, UoS in respect of non half hourly metered customers and half hourly metered customers is separately invoiced through different systems, and our charges reflect the costs of the relevant system over the number of customers of that type. The MPAS system costs are spread over all customers as all customers have equal use of it.

2.5 Volume driven costs are the asset costs of the network, including provision and operation and maintenance, and rates which are allocated on a long run

marginal cost basis as detailed below. These are recovered through UoS unit charges.

- 2.6 Supplier driven costs include metering services and are charged on a transactional basis. Further detail about these is included below.

**Describe how network asset charges are derived and explain how these are hypothecated to customer groups**

- 2.7 The following gives a high-level breakdown of the steps used. A long run marginal costing approach is used to give relevant cost messages to customers about their usage of electricity. Effectively, the costs are allocated to those time periods where any increase in consumption would result in us to having to spend capital reinforcing the network. The final price is weighted by customers' demand during those, costly, periods.
- 2.8 Notionally, the remaining half hours attract no charge under this method as the existing network can be considered to be a sunk cost. In this way, total costs are still recovered, but network users are given the right cost messages.
1. Asset costs are derived from the current costs of the assets needed to establish a theoretical network of 500MW capacity, with the same characteristics as our network, including rural/urban split.
  2. These costs are scaled to the capacity of our actual network to derive a notional cost for our system.
  3. The costs of NGC exit charges are added to this.
  4. Costs associated with EHV customers are removed to give the cost for regulated customers only.
  5. A return on capital is added, derived from the rate of return allowed by the regulator.
  6. Customers at each voltage level are allocated the costs associated with the parts of the network that they use e.g. a HV customer does not get any LV substation or LV network costs.

7. Costs are then allocated on a demand weighted basis to the top 20% of half hourly demands during the year. This replicates a long run marginal cost approach as those top demands are more likely to cause us to incur the costs of reinforcement.
8. The year is split into seven time periods and the calculated costs are allocated to these to derive a simplified cost for each half-hour of the year, for each of HV and LV customers. These time periods are provided later, in the worked example.
9. Customers are allocated to a LLFC group based on the nature of their point of connection and metering. In addition, the half hourly demand profile for each customer LLFC group is estimated.
10. The yardstick unit price is the weighted average of the cost of those seven time periods weighted by the demand profile for the given customer LLF group.
11. The LV seven rate prices are given in our Condition 8 Statement (LLFC 86). The price of an unrestricted customer (LLFC 3) will be the demand weighted average of those prices, based on the typical demand profile of that group of customers.

**Explain the main elements of, and activities associated with, network operating and maintenance costs. Outline how these costs are calculated and hypothecated to different customers**

- 2.9 Operating and maintenance costs are treated as asset charges and included in the above methodology on a pro rate basis to the assets.

**Describe how the costs of electrical losses are treated**

- 2.10 The network must be planned to take losses into account and this will drive the costs associated with our network as a whole, as modelled in our asset costs. Therefore, losses are not specifically included but are reflected in the asset costs as outlined above.

### **Identify what other activities are also captured in UoS charges**

- 2.11 Regulated use of system income also includes metering, for which we separately charge. We split metering charges between meter provision and meter maintenance. The meter provision charge is based on the capital cost of providing a meter spread over the working life of the meter, and this is given as a standing charge per month. Meter maintenance charges reflect the cost of the time and materials required and are set for each type of service.

### **Outline how other costs are hypothecated to different users**

- 2.12 Meter provision charges are levied on suppliers based on the numbers and types of meter that their customers are using. Due to changes of supplier, we take the simple average of the number of meter points for which the supplier was liable at the start and end date of the invoice period.
- 2.13 Meter maintenance is charged to suppliers based on the volume of each of the services that have been performed on their behalf each month.

### **How these methods and principles are modified to ensure compliance with the distribution price controls**

- 2.14 Following the distribution price review we have changed the rate of return that we apply from 7% to 6.5%, in line with regulatory guidance.
- 2.15 The first step of the process of producing our final charges, is to determine the amount of income that we are allowed to recover through the condition 3A price control formula. To do this we must forecast customer growth, unit volumes by basket, and losses. The income in the formula is also dependent on the preceding year, through both the unit term and the 'k' term (under-/over-recovery correction factor), so we must forecast the current year's outturn of these variables as well.
- 2.16 The methodology outlined previously will not produce an exact match to allowed revenue. We therefore scale our unit price yardsticks to produce our final unit prices, hence maintaining the relative cost messages. We do not scale customer or supplier driven charges, as these do not contain marginal cost messages. By scaling unit prices we try to ensure that the sum of our expected

income, for all charge types, equals our allowed revenue. Prices are set using best endeavours to ensure that this value is not exceeded. However, any inaccuracy in our forecast volumes and customer numbers (which is over two winters for an April price change) will, through the k factor in the subsequent years, be self correcting in the long run.

**Provide an illustrative example of how UoS charges for the standard domestic tariff are derived**

2.17 Note that we do not differentiate between domestic or non-domestic customers. This is because the costs are dependent on factors such as non half-hourly or half-hourly metered, etc, and not on the nature of the premises being connected.

2.18 The derived LV costs over our seven periods are as given in our Condition 8 Statement:

	Period 1	Period 2	Period 3	Period 4	Period 5	Period 6	Period 7
LV p/kWh	2.38	0.75	0.08	0.58	14.90	1.15	0.50

The demand profile we use for an unrestricted customer is as follows:

	Period 1	Period 2	Period 3	Period 4	Period 5	Period 6	Period 7
Unrestricted	0.75%	2.95%	24.38%	3.86%	3.78%	7.82%	56.47%

This produces a weighted average unit price for an unrestricted customer of 1.02p. In this way, LV customers are all charged the same base prices but their final charge depends on their pattern of demand.

Our seven periods are defined as follows:

Period 1 between 01.00 and 02.00 each day during each month from November to February inclusive.

Period 2 between 00.30 and 03.00 each day during each month from October to March inclusive, excluding period 1.

Period 3 between 18.00 and 08.00 each day from April to September inclusive and between 21.00 and 00.30 each day from October to March inclusive and between 04.00 and 06.00 each day from October to March inclusive.

- Period 4        between 07.00 and 12.30 each weekday from Monday to Friday inclusive, during January and February.
- Period 5        between 16.30 and 19.00 each weekday from Monday to Friday inclusive during each month from November to February .
- Period 6        between 16.00 and 21.00 each weekday from Monday to Friday inclusive during each month from October to March inclusive, excluding period 5.
- Period 7        other times.

(All times are clock time)

**Describe the sensitivity of network costs to changes in demand**

- 2.19    Network reinforcement costs are dependent on growth in demand at given times of the year. Growth in demand at times when the network is less utilised do not cause reinforcement costs as the growth can be absorbed by any spare capacity at those times. Our methodology reflects this.

**Demonstrate what proportion of connection costs, if any, are recovered through UoS tariffs**

- 2.20    The cost of any assets associated with a new connection are included in the connection charge together, where applicable, with an element of reinforcement costs. Remaining reinforcement costs are recovered through UoS charges. Allowances against the connection charge are given in respect of the new assets, based on the present value of future income streams expected from the new assets to the extent that reinforcement is avoided.

**Identify any areas where you envisage changes to methods and principles of charging**

- 2.21    We do not propose any changes to our methodology or principles of charging for April 2001.

## Appendix 3 East Midlands Electricity

### Introduction

- 3.1 As we have explained previously, our DUoS pricing is moving progressively towards reflecting the regulation. The primary purpose of DUoS tariffs in our view is to recover the revenue we are allowed by the distribution price control, and, as previously agreed, we are now in the early stages of moving our price-setting away from the cost-reflective methods and principles embodied in the Boley and Fowler paper to a methodology where our prices and revenue streams better reflect the regulatory formula.

This has two effects directly relevant to this exercise:

1. Some of the guideline questions in the information request are no longer directly applicable;
2. This new method is concerned with the overall effects that proposed tariffs have on consumers. Cost justifications for individual charging elements take a “back seat”, and, in trying to better reflect the regulation, achieving tariffs which look “regulatory consistent” becomes more important. For instance, we would expect the average pence per unit (ppu) for an HV consumer to be less than that for a LV consumer.

### The Regulation Reflective Method – Where We Want To Get To

- 3.2 Our aim is to align our revenue streams and prices as best we can with the price control formula. More specifically, this means:
- ◆ we aim eventually to obtain 50% of our annual allowed revenue from fixed charges and 50% from variable (in fact, in tariff terms, because we add the pass-through NGC exit charges to the fixed element, this translates to approximately 54% fixed and 46% variable);
  - ◆ the fixed charge revenue, recovered through standing and kVA capacity charges, will remain largely cost-reflective;

- ◆ the variable charge revenue, recovered through kWh unit rates, may eventually be aligned with the allowed income per marginal unit which falls out of the use of the tariff basket weights in the regulatory formula. This could mean having just four p/kWh unit rates in future.

3.3 The main reason for doing this is to ensure minimum divergence between allowed and actual income. The following table illustrates the rationale for better reflecting the regulatory formula:

	Charging Structure		
Volume out-turn	100% Fixed	100% Variable	54 : 46
<i>As forecast</i>	Zero k	Zero k	<b>Zero k</b>
<b>Below forecast</b> (- 5%)	Over recovery (£6m)	Under recovery (£8.6m)	<b>Zero k</b>
<b>Above forecast</b> (+ 5%)	Under recovery (£6m)	Over recovery (£8.6m)	<b>Zero k</b>

3.4 The table shows what happens to allowed revenue when there are variations from the forecasts made at the time tariffs are set. Three charging structures are contrasted; the two extremes of DUoS prices being either all fixed or all variable, and prices that mirror the regulation.

3.5 In addition, estimates of the £m effects are shown if the variation is 5% above or below the original volume forecasts. Whilst 5% is at the extreme end of likely variations, it serves to illustrate a point.

3.6 The conclusions we draw from this table are:

- ◆ Only charges reflecting the regulation are likely to deliver a zero under- or over-recovery.

- ◆ The effects of being above or below forecast are not “symmetrical” – being below forecast could result in either an over- or an under-recovery; it all depends on the particular tariff mix.
- ◆ Forecasts are rarely 100% accurate, so, unless prices reflect regulation, there will always be resources expended on managing under, or over, recoveries.

3.7 The main benefits to us of making DUoS prices better reflect the price control are:

- ◆ the divergence between income and allowed revenue is minimised – this, in turn, minimises the risk of financial penalties or breaches of Licence regarding recovery;
- ◆ there will be no need for internal mechanisms for dealing with under- and over-recoveries;
- ◆ tariff-setting and its associated activities will become much simpler.

3.8 In addition we see benefits for other stakeholders:

- ◆ the clear link to the regulatory formula improves transparency;
- ◆ avoids the many questionable assumptions of cost-reflective methods;
- ◆ DUoS pricing will become more stable and predictable;
- ◆ there will be no need for “surprise” rebates;
- ◆ DUoS tariffs will reduce in number and become simpler.

#### **Tariff-setting For 2000/01**

3.9 The 2000/01 prices, which we discussed and agreed with Ofgem, were the first step towards better reflecting the price control formula. The P0 cut of the distribution review gave us the opportunity to make a step-change in the rebalancing of our prices. Specifically it enabled us to aim at achieving proportionally less of our revenue from the variable unit charges and, in turn,

raise the proportion of revenue from our fixed charges, without having to raise most tariff elements.

- 3.10 In addition to going through the methodology with Ofgem, we discussed feedback we got from suppliers and reviewed the practical impacts of our new tariffs.
- 3.11 The prices for 1999/2000 applied to 2000/01 volumes would have produced a revenue mix of 41% fixed and 59% variable, some distance from the ideal split of 54:46.
- 3.12 As a result our main aims at the outset of the tariff-setting process for 2000/01 were:
- ◆ rebalance the fixed/variable split;
  - ◆ start moving towards tariff-basket-reflective unit rates;
  - ◆ abandon the winter/summer differentials in the large LV and HV tariffs;
  - ◆ deliver reductions for all tariff/consumer groups;
  - ◆ maintain the average pence per unit (ppu) differentials between tariff/consumer groups.
- 3.13 In addition, and aimed at reducing longer-term billing costs, we set about introducing new tariffs for our medium non-domestic consumers so that they could be billed using the supercustomer rather than the site-level method.
- 3.14 In the event, following consultation with suppliers, we agreed that we would implement the abandonment of the winter/summer differentials in the 2001/02 tariff-round, but all the other objectives were achieved. In essence, we did this by maintaining the existing fixed charges and lowering the unit rates. And we anticipated achieving a revenue-split of around 49% fixed and 51% variable.

### **How The Fixed Charges Were Set**

- 3.15 We wanted to increase the proportion of fixed revenue. This meant we could either maintain fixed charges (and put all of the P0 cut in unit rates) or raise fixed

charges (and make steeper decreases in unit rates). Eventually we chose to maintain most fixed charges, mainly on the grounds that they were broadly cost-reflective (in the old methodology, reflecting the underlying consumer-related costs of metering, maintaining connections, NGC exit charges and operational expenditure such as billing, customer service and overheads). The only initial (see later) exceptions to this were the standing charges for 3-phase small non-domestic consumers, which we had been planning to increase on the grounds of cost-reflectivity anyway.

- 3.16 We knew that this mix would not achieve the “ideal” fixed revenue target of 54%, but we were concerned about the tariff disturbances of other options and sensitive to supplier and end-consumer pressures.

### **How The Variable Charges Were Set**

- 3.17 We had two aims with our variable charges:

- ◆ to make unit prices more closely resemble the allowed revenue per marginal unit (ARPMU) for each tariff basket;
- ◆ to get proportionally less of our total revenue from unit rates.

- 3.18 The tariff basket ARPMUs fall out of our model of the price control formula. As the name suggests, we calculated what an extra unit would be worth to us in allowed revenue terms for each tariff basket. To establish this we flexed the price control model to take account of an extra GWh for each tariff basket in turn. The resultant increases in allowed revenue were divided by the GWh to get a pence per kWh rate for each tariff basket. These rates became our benchmark tariff basket prices. The values we used for 2000/01 were as follows:

<b>Tariff Basket</b>	<b>Benchmark Allowed ppu</b>
<b>LV1</b>	0.655
<b>LV2</b>	0.226
<b>LV3</b>	0.638
<b>HV</b>	0.258

- 3.19 With these as benchmarks, the questions for variable charges were:
- ◆ which unit rates should we change?
  - ◆ in what tariffs?
  - ◆ and by how much?
- 3.20 To help us assess our proposals we used overall tariff consistency, minimal tariff disturbance, and average reductions for all consumer groups as checks.
- 3.21 What followed was essentially an iterative process of running a number of unit rate proposals against these checks to come up with a preferred option. We then consulted with suppliers and revised our plans in the light of some of their concerns. In particular, as mentioned earlier, we agreed to delay implementation of our initial plan to abandon the winter/summer differential immediately because the timing would “punish” suppliers, who had already contracted on the basis of such a differential.
- 3.22 This also led to us changing the fixed charges for larger consumers.
- 3.23 The eventual outcomes for unit rates were as follows:
- ◆ consolidation and significant cuts in the unit rates for domestic and small non-domestic consumers;
  - ◆ maintenance of medium and large LV rates, but with the declared intention to abandon winter/summer rates in the coming round of tariffs;
  - ◆ maintenance of HV unit rates, with the exception of a decrease in the winter day rate, but again with the declared intention of abandoning winter/summer rates in the coming round of tariffs.

## Notes and Remarks on Specific Information Requested

### Derivation of the Standard Domestic Tariff

#### Reason for changes to standard domestic tariff

Tariff element	1999/2000	2000/01	Rationale
Standing charge (p/day)	6.3	6.3	Would have increased to achieve increased fixed revenue target, but thought it prudent to leave.
Unit rate (p/kWh)	1.5	0.9	Decreased to get closer to 0.655p ARPMU and achieve overall average reduction for this tariff group.

#### Losses

- 3.24 In our methodology, network losses are not explicitly accounted for. Effectively, we assume they are accounted for in the tariff basket weights.

#### Sensitivity of Network Costs to Changes in Demand

- 3.25 Network costs, as suppliers or end-consumers might see them, through their DUoS charges, are clearly *not* sensitive to changes in network demand, except perhaps in the general sense that Ofgem sets allowed revenue to take into account the investment needed for changes in total system demand.
- 3.26 Looking at a more detailed, and perhaps more meaningful level, do changes in the demand of a particular tariff group drive or affect network costs?
- 3.27 Theoretically the answer is yes. In practice though, the answer is no.
- 3.28 In theory, the cost-reflective methodology would pick up a change in tariff demand through a change in that tariff's peak capacity coincidence factor. This measures the proportion of a tariff group's peak demand, which is used at the time of system peak, and it is used to determine what proportion of the total average cost of network capacity the tariff should incur. Importantly, if the coincidence factor increases, the network costs attributable to that tariff also increase, and of course, in theory, this should be passed on to the tariff group.
- 3.29 There are numerous problems with this, even in theory.

- 3.30 Picking up an accurate and significant change in demand for a tariff group is difficult. Peak capacity coincidence factors can only be derived from load research data for relevant tariff groups. Whilst there is a programme of load research undertaken by the Electricity Association, from our perspective it suffers from a number of problems. The data is mainly national, samples are typically small, the research is geared to the demands of suppliers and has insufficient coverage of our DUoS tariff groups, and it is very expensive.
- 3.31 But even if peak capacity coincidence factors more relevant to the East Midlands and our particular tariff groups were available, there would still be problems in determining how changes in tariff demand affect real costs. This is because the total average cost to which a coincidence factor is applied is not representative of actual network costs.
- 3.32 In the cost-reflective methodology the total average cost of providing network capacity is derived from the "500 MW model". Typically this will have a number of questionable assumptions built into it, but key amongst them are that costs are based on building a network "from scratch", and that costs are based on a network which peaks during the day only.
- 3.33 These assumptions contrast vividly with the reality of our network, with its sunk costs, its highly localised "hot spot peaks" at various times of the day, and its more general under-utilisation.
- 3.34 In truth, and with the exception of extreme circumstances, a tariff group could change its pattern of demand and we would be hard pressed to know about it, let alone incur any extra costs.
- 3.35 The only place where there is cost sensitivity to patterns of demand is in connection charges. Here the future demand pattern for a particular consumer is put into the context of the local network capacity at a particular point in time. If the additional demand requires additional capacity higher up the network, and so incurs network investment costs, then we charge for it, subject, of course, to limitations such as the "25% rule".

### **DUoS and Connection Costs**

- 3.36 The relationship between DUoS and connection costs is an issue for us. Our tariff support allowances (the mechanism intended to ensure newly-connecting consumers are not “double-charged”) were set in 1995/96, during the last distribution review period, and are based on an understanding of the cost-reflectivity and allowed revenue current at the time. They have not changed since then, in spite of our having a significant reduction in our allowed revenue in the meantime. We suspect there is a strong case for abandoning tariff support.

### **Changes to Charges**

- 3.37 In general, we expect our moves to better reflect regulation to result in simpler and less DUoS tariffs. However, there are two areas, which are likely to lead to new charging approaches:

#### *NETA and Meter-splitting;*

- 3.38 The possibility of single sites having more than one supplier has implications on how we apply fixed charges. Do we charge one supplier in the same way we do now? Or do we split the charges somehow? And in what way? This is an issue.

#### *Embedded Generation and Export Charges;*

- 3.39 Similarly, this is an issue, and one being debated at a national level.

## Appendix 4 London Electricity

- 4.1 To aid the reader, the questions contained in Ofgem's Information Request are reproduced in bold italics below. Each question is followed by London Electricity's response.

***Describe to what extent the methods and principle adopted differ from those set out in the seminal paper by Boley and Fowler (1977)***

- 4.2 Given the broad-brush nature of the Boley and Fowler paper, LPN's approach has been and is fundamentally the same. Because of the nature of our system, the analysis of reinforcement costs is slightly different in that the 33/11kV stage is absorbed within the 132/11kV level and is not separately disclosed. Otherwise the structure and calculation of yardstick costs is very similar.
- 4.3 For the future, we believe these principles are still sound. The costs of distribution are dominated by capital costs arising from the network developed over time to meet the requirements of a multiplicity of customers of different sizes and voltage connection. Most costs are therefore shared rather than entirely associated with individual customers. The method of cost allocation starts from the assumption that in the long run all system costs are incurred to meet demand from customers. It should be possible therefore to estimate the impact of different customer demands on system costs, again in the long run.
- 4.4 However, rather than trying to disentangle costs already incurred and assign them to existing customers and recognising that some customers for whom costs were incurred are no longer connected, more economic purpose is served by trying to signal the extra costs in the long run of meeting extra demand from customers. To the extent that the nature of such an expansion of the system might differ from the way the system has been developed up to now, the sum of the cost estimates might differ from existing costs. As a result, charges may eventually have to be scaled in some way to the required revenue.
- 4.5 The Boley and Fowler methodology never envisaged that yardsticks should reflect cost increments at the margin with no regard for the nature of the system as a whole. They were meant to reflect the cost of replicating part of the system to meet a discrete, representative quantity of load. The advantages of this were

that LRMC (Long Run Marginal Cost) values would not give too big a difference from overall replacement costs and that the message given would not represent false, short term messages about particular opportunities on the system. The importance of stable, long-term messages is based on the fact that assets are long-lived and customer's load also generally stays for a very long time (e.g. 20 years or more). Hence, the prominence given to replacement costs as well as reinforcement costs in the yardstick model should lead to stability in yardstick costs over time. We believe that this shift of emphasis is entirely consistent with Boley and Fowler principles and those subsequently confirmed at vesting.

***Identify the cost drivers captured within use of system charges***

- 4.6 The main cost drivers are the capacity and the maximum demand of the network.

***Describe how network asset charges are derived, and explain how these costs are hypothecated to customer groups***

***Reinforcement model***

- 4.7 The reinforcement model contains all the network elements necessary for the immediate connection of new load and to provide additional capacity upstream in the network to both meet new load and load growth of existing customers. The model derives the real cost (£/kVA) of delivering new load to the distribution network at every voltage level throughout the network.
- 4.8 The model is split into three areas of load density:
- ◆ High Density > 20MVA/Km<sup>2</sup>
  - ◆ Medium Density 6 MVA/Km<sup>2</sup> to 20MVA/Km<sup>2</sup>
  - ◆ Low Density < 5MVA/Km<sup>2</sup>
- 4.9 The assumption is that the need to reinforce the network and the method of construction varies significantly across the three load density areas and hence the costs of reinforcing the network vary significantly too.

4.10 *The output of the model is a £/kVA value of supplying a number of generic load types at the different voltage levels as appropriate. These generic load types are:*

- ◆ Housing Day Load
- ◆ Housing Night Load
- ◆ Small Commercial/Industrial Load
- ◆ Large Commercial/Industrial Load

4.11 For each generic load type a series of assumptions are made about the method of connection and associated upstream reinforcement, where this is required, and a prime cost of this connection is calculated. Capital overheads are then added to derive the resultant £/kVA value.

#### *Replacement Model*

4.12 This model provides for the replacement, as far as necessary, of the entire existing distribution network, apart from immediate service connections. It is split by the same load density as the reinforcement model.

4.13 The assumption is that the need to replace the network and the method of construction varies significantly across the three load density areas and hence the costs of replacing the network vary significantly too.

4.14 Like the reinforcement model, there are a number of assumptions inherent in each of the £/kVA results. The derivation of the £/kVA values is similar across asset types:

LV Mains

HV/LV Transformation

HV Supplies

HV Mains

EHV Mains 132kV

EHV Mains 33kV

EHV/EHV transformation 132/33

EHV/HV transformation 33/11

### *Unit Yardstick Model*

- 4.15 The reinforcement and replacement models are blended into a composite model by using weights that have regard to the rate of reinforcement for new load and the rate of asset replacement. The costing results of the composite reinforcement and replacement models are input into the unit yardstick model.
- 4.16 Unit Yardstick calculations use the following network exit levels: -
- a) 132kV
  - b) 132kV/11kV transformation
  - c) 11kV
  - d) 11kV/LV transformation
  - e) LV (i.e. 415/240V)
- 4.17 Half-hourly demand shapes are created for customer groups. Half-hourly customers are grouped by load factor bands and voltage. Non half-hourly customers are grouped by profile. Demand analysis is then conducted on the half-hourly demand shapes.
- 4.18 The half-hourly demand shape for each customer group is analysed and then broken down into peak system stress times. Peak system times on the 'upstream' system are as follows: -
- ◆ Winter 17:00 to 18:30
  - ◆ Summer 09:00 to 13:00

Peak demand times at the local system level are more related to the peaks of the particular load group as there is less load diversity than is the case further upstream.

- 4.19 Peak system stress data is broken down by Network Asset Levels. The coincidence factor is calculated by taking the demand during peak system stress and dividing by the maximum demand for each customer group. The coincidence factor is then multiplied to the p/kVA/yr taken from the composite reinforcement and replacement model to create the marginal cost. The marginal costs are summed across the asset levels to produce the overall yardstick for the customer group.

*Standing Charge Yardstick Model*

- 4.20 The local costs of connection to the customer (largely comprising the service cable and associated assets) are included as an annual sum in the Standing Charge yardstick for each user group.

***Explain the main elements of, and activities associated with, network operating and maintenance costs***

- 4.21 The main elements are system control, planned maintenance and unplanned (emergency) maintenance and repairs.

***Outline how these costs are calculated and then hypothecated to different customers***

- 4.22 The overall cost of these activities is quantified and the relevant percentage of the asset cost is derived. These percentages are then incorporated in the cost yardsticks as an addition to the annuitised cost of capital (which generally is based on a 6.5% rate of return over a 40 year life) percentage to produce an annual cost for each asset employed.

***Describe how the costs of electrical losses are treated***

- 4.23 Losses are included within the yardstick model. The losses used by exit level are as follows: -

	<b>LV</b>	<b>HV</b>
<b>(i) 132kV</b>	7.5%	2.8%
<b>(ii) 132kV/11kV</b>	5.9%	1.3%
<b>(iii) 11kV</b>	4.7%	0.4%
<b>(iv) 11kV/LV</b>	3.4%	-
<b>(v) LV</b>	1.4%	-

- 4.24 Line loss factors are calculated for the following groups of customers: -

- ◆ HH metered and settled HV
- ◆ HH metered and settled LV
- ◆ Profiled monthly seasonal HV

- ◆ Profiled monthly seasonal LV  
Business profiled LV
- ◆ Residential profiled LV
- ◆ Public Lighting & unmetered LV

These categories ensure that the correct losses are applied to each customer group.

- 4.25 LPN provides cost messages to customers by having different losses based on Power Factor for half hourly and profiled monthly customers. If a customer has a low power factor, high losses are applied. LPN believes that this gives customers an incentive to improve their power factors.
- 4.26 While the average costs of electrical losses on distribution asset investment are included in cost yardsticks, and the average energy costs are reflected in the published Line Loss Factors, there remains a requirement to address the issue of the impact caused by customers power factor. It has long been recognised that low power factor can cause electrical losses to significantly increase; at the extreme this could be five fold or more.
- 4.27 Many customers have, over the years, installed power factor correction equipment to cure the problem and thereby reduce energy lost in distribution. In order to maintain this cost message, LE have DUoS prices for the half-hourly market and the larger end of the business profiled market that contain a charge for Reactive Units (kVARh) where the power factor falls below 0.9486 lagging; this charge reflects the additional distribution system capacity costs to support low power factor loads. The higher level of energy losses caused by low power factor sites is reflected by LE through having nine bands of Line Loss Factors for half-hourly sites; the lower the power factor, the higher the Line Loss Factor applied.

***Identify what other activities are also captured in use of system charges***

- 4.28 Other activities included within use of system charges are Operational Rates, NGC exit charges and business overheads.

***Outline how other costs are hypothecated to different users***

- 4.29 LE are charged Operational Rates on the basis of a formula that uses installed transformation capacity as the driver. We therefore include this item in our cost yardsticks according to the requirement for transformation capacity brought about by the different users.
- 4.30 NGC exit charges are attributed to different users based on their contribution to winter weekday early evening peaks.
- 4.31 Business overheads, such as the costs of billing and registration, are apportioned into the Standing Charge yardsticks except where they are associated with the operations and maintenance element in the unit yardsticks.

***How these methods and principles are modified to ensure compliance with the distribution price controls***

- 4.32 After producing all the yardsticks, the forecast customer numbers and units are applied to the yardsticks. The result is different to the distribution price control due to the many assumptions in the process. The yardsticks are then scaled to meet the allowed income from the distribution price control.
- 4.33 Prices are not necessarily set at the same percentages of the original yardsticks. While a prime concern in formulating the final DUoS prices is cost reflectivity, we are mindful that there is a need to avoid creating too much price disturbance from year to year as this might cause difficulties for suppliers and the final customers and might also impede the competitive process.

*Provide an illustrative example of how use of system charges for the standard domestic tariff (credit) are derived.*

Standing charge yardstick

Domestic Unrestricted Credit	
	£
Minimum supply cost	A
Less connection charge	B
Net supply capital cost	C = A - B
	£/year
MSC Annuitised Capital	D (a percentage of C)
Metering Annuitised Capital	E
Idle Service Allowance (3%)	F
O&M costs for meters	G
O&M costs for Connection	H
Business Overheads	I
Cost per year	J = D + E + F + G + H + I
Total cost (pence per day)	K = J/365

Unit yardstick

*Tariff Domestic Unrestricted*

*Units/kW Z*

Distribution System Costs	P/kW/year	Marginal p/kWh	Coincidence Factor
132 KV reinforcement @ plus losses of 7.5%	L	= L/Z * R = L/Z * R * 7.5%	R
132/11 KV reinforcement @ plus losses of 5.9%	M	= M/Z * S = M/Z * S * 5.9%	S
11 KV reinforcement @ plus losses of 4.7%	N	= N/Z * T = N/Z * T * 4.7%	T
11 KV/LV reinforcement @ plus losses of 3.4%	O	= O/Z * U = O/Z * U * 3.4%	U
LV reinforcement @ plus losses of 1.4%	P	= P/Z * V = P/Z * V * 1.4%	V
NGC Exit @	Q	= Q/365 * W	W
Business Rates		X	
Total cost		Y = SUM(COLUMN)	

	Yardstick	00/01 price
Standing Charge	K	5.720
Unit Charge	Y	1.026

***Describe the sensitivity of network costs to changes in demand***

- 4.34 LPN's investment policies are aimed at delivering the maximum customer value using efficient processes in the forecasting, planning and implementation of projects.
- 4.35 *Load forecasts, both energy usage and maximum demands are produced at company and local area level. These, together with customer applications form the basis of new business and reinforcement investment plans for the distribution network. The proposed levels of investment take into account anticipated changes in load factor and diversity, both of which can have a significant effect on demand levels at the higher voltage levels on any distribution system.*
- 4.36 Projected investment levels for the new business and reinforcement categories were set out as part of the Business Planning Questionnaire for the five-year period 2000/1 to 2004/5. These were based on forecasts of new business connection activity and load forecasts at the time. Clearly any movement in the economic activity and load forecasts for London over the period of the present review will affect the levels of expenditure for network costs. This will appear as changes in new business expenditure and in the reinforcement category as increased demands affect deep reinforcement costs.
- 4.37 A clear example of this is beginning to emerge in the telecommunications and Internet data arenas. The advent of the Internet Data Centres (or Telehouses) in London, well heralded in the press, is having significant effects on new business and reinforcement expenditure. Applications for these centres, many of which are centred on London as the European hub for the industry, are in the range 20-75MVA. As a conservative estimate, applications for individual Telehouses total some 1,000MVA in London, about a quarter of the present maximum demand. Clearly, this will have a significant effect on network costs.

- 4.38 Even if demand changes do not occur, network costs will always occur as a result of load movement or churn. Existing sites in London are continually being developed with the result that new business and possibly reinforcement costs will continue despite no great overall demand increase. It is important therefore to relate new business expenditure to the total levels of new capacity applied for and installed and not just to the incremental increase in demand and unit consumption.
- 4.39 In London, network costs are driven by various factors including load density which can be as high as 200MW/km<sup>2</sup>. Other factors are that London's distribution network is largely underground, congestion of streets and footpaths makes excavations difficult and time-consuming and substation accesses for plant and personnel are often difficult.
- 4.40 Any increases in demand will only serve to magnify these difficulties, resulting in increased network costs. However, the relationship between network costs and demand changes is a complex one for the reasons set out previously. The new e-economy is presenting distribution businesses with even greater challenges for which there is little or no precedent.

**Demonstrate what proportion of connection costs, if any, are recovered through use of system tariffs**

- 4.41 The connection costs charged to customers are reduced by an amount (termed a connection allowance) which represents the expected recovery of costs through the ongoing DUoS charges. This is calculated with reference to the voltage and type of assets required to make the particular connection. The proportion will therefore depend on the individual circumstances of each connection.

**Identify any areas where you envisage changes to the methods and principles of charging**

- 4.42 LPN has no plans to change our methodology at the moment. However, all our assumptions are liable to be reviewed in the light of changed circumstances.

## Appendix 5 ScottishPower Gro up (including Manweb)

### *Overview*

- 5.1 The methodology employed in deriving Distribution Use of System Charges seeks to recover the revenue target as set by the Distribution Price Control in such a way as to be consistent with our Licence obligations in respect of non-discrimination and cost reflectivity.
- 5.2 A common underlying approach to pricing applies within the ScottishPower Group for the two distribution areas of ScottishPower and Manweb. Where minor differences, arising from regional variation in cost drivers, do exist, this is highlighted in the text.
- 5.3 The general principles applied are premised on the underlying assumptions within the price control in respect of CAPEX and OPEX provisions and reflect the company's current cost base, with account taken of anticipated CAPEX requirements. The broad principles are consistent with those outlined in the Boley and Fowler paper. Any differences from the Boley and Fowler approach arise in the methodology employed to reflect the long run costs of the developing the network.

### *General Principles*

- 5.4 The yardstick model seeks to allocate the distribution business costs in full to individual customer groups, under the three main categories: capital costs, operation & maintenance costs and customer-related costs, thus avoiding the scaling inherent on a "greenfield" model. Within each of these categories, there is a drive to reflect as far as possible the underlying assumptions within the price control in respect of the level of operating costs and anticipated return on capital outlay. Included in these costs is the cost of connection to the Transmission system, which is chargeable to the distribution business.
- 5.5 The main cost drivers in the provision and maintenance of a supply to a customer are the voltage at which the customer is connected and the capacity/demand provision required by the customer. The process of allocation

of costs and derivation of charges to individual customer groups will therefore reflect these main cost drivers.

- 5.6 Customers are connected at one of the main distribution voltages: EHV (132kV<sup>6</sup> or 33kV), HV (11kV) and LV (400v). The underlying process is to firstly derive the cost of providing and maintaining each of the main voltage levels on the network. These costs are then assigned to the customer groups contributing to the loading at that point on the network in proportion to their relative demand / capacity requirements. Customer related costs are assigned on a customer basis, weighted to account for the relative cost to serve each customer group.
- 5.7 For illustration, the domestic customer base is connected to the LV network. As such these customers are required to contribute to the costs of provision and maintenance of each of the voltage levels. The domestic charges will therefore incorporate a contribution to the LV, HV and EHV networks plus a contribution to the cost of the connection to the transmission system. The proportion of the costs assigned to the domestic customer group will reflect their contribution to the overall demand requiring to be supported on each specific layer of the network.

#### *Allocation of Network Costs*

- 5.8 The yardstick model will firstly assign costs within the appropriate network categories on the basis of the cost of provision and maintenance of each of the main voltage levels i.e.
- ◆ 132kV network (Manweb only, in ScottishPower area these are transmission costs)
  - ◆ 132/33kV network (Manweb only, in ScottishPower area these are transmission costs)
  - ◆ 33kV network
  - ◆ 33/11kV network
  - ◆ 11kV network
  - ◆ 11/400v network
  - ◆ 400v network

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<sup>6</sup> Manweb area only, for ScottishPower 132kV is a transmission voltage

- 5.9 The published charges for the Manweb distribution area have traditionally differentiated between “network” and “substation” connected customers. This differentiation has been maintained but has not been reflected in the ScottishPower area.
- 5.10 The costs to be recovered include all direct and indirect costs other than that proportion of connection cost which are recovered directly from the customer through capital contributions. The proportion of connection costs recovered directly from customers is as agreed with Ofgem under the terms of the price control. These costs can be categorised as follows:
- ◆ Direct operating costs: revenue cost of labour, material stores and contractors for carrying out direct work on the network.
  - ◆ Indirect operating costs: the major items in this group are rates, indirect salaries, training and welfare, and transport.
  - ◆ Depreciation: depreciation is calculated in a manner consistent with the price control provisions.
  - ◆ Return on capital: the yardstick model is constructed such as to allocate the target income to each customer group. Having determined the costs incurred , the return on capital becomes the balancing item in achieving the targeted income level.
- 5.11 Each of these cost categories relate to the construction, operation and maintenance of the network. Where system records allow a direct allocation of costs to a specific network voltage or to a specific customer (in the case of EHV connected sites) these costs are assigned on that basis. Otherwise, costs are assigned to each voltage category in proportion to the value of the network assets.

Transmission Exit charges:

For the Manweb distribution area, these are charges levied by NGC for the assets at the point of connection with the distribution business. The pass through of these costs is embedded in the provisions of the Distribution Price Control.

For the ScottishPower distribution area, these are charges levied by ScottishPower's Transmission Business for the assets at the point of connection with the distribution business. In the interests of price stability it was agreed with Offer that the recovery of these costs would be best achieved through the vehicle of the published distribution charges.

These costs are allocated in a similar manner to all other network related costs.

#### Treatment of Customer Related Costs

Some elements of costs are customer related and are assigned on the basis of customer numbers weighted to take account of the relative cost to service the different customer groups. These costs include customer service and the provision of those metering related services which are the responsibility of the distributor.

#### *Derivation of demand requirements*

- 5.12 Having assigned costs to each voltage level, these costs are assigned to each customer group in proportion to the contribution to overall demand to be supported at that part of the network.
- 5.13 The contribution to demand by each customer group is determined on the basis of load research available either by way of industry research or, to a lesser extent, on the basis of individual company based research. The overall level of demand to be supported at each level reflects the final metered sales adjusted to take account of the losses incurred in delivery of those metered sales.
- 5.14 Historically, the method of determining contribution to overall demand from each customer grouping has differed between ScottishPower and Manweb. Whilst these differences are currently reflected within the yardstick model, this will be subject to review as described below.
- 5.15 For the Manweb load, the demand is determined on the basis of the weighted average of demand on the system at the three peak periods of the day. These three peak periods reflect times at which individual networks have historically been found to peak. In the case of ScottishPower the demands are determined in part on the basis of the demands at the time of overall system peak and also on

the peak demand of each individual customer group. This methodology which was agreed with Offer at vesting has been the subject of review and consideration is being given to move to reflect a broader definition of demand on the network, akin to the methodology encompassed in the Manweb cost allocation process

## Appendix 6 Midlands Electricity (GPU Power UK Ltd)

- 6.1 GPU has use of system (DUoS) charges which consist of up to three elements; a fixed charge per month/day; an available capacity charge based on kVA; and a unit element based on kWh. The theory suggested by Boley and Fowler would indicate that distribution costs fall principally in to the first two of these. There are factors, however, which make the use of kWh both possible and in certain cases desirable. kVA charges are undesirable for smaller customer where the cost of metering and billing would be disproportionately high compared to the impact of the customer on network costs. kWh can only be used effectively where there is sufficient commonality of a customers load profile within a class to assume a relationship between maximum demand and kWh. This will go right down to the LV network for domestic and small non-domestic customers, but is only appropriate to cover higher network costs for larger customers where there is the impact of sufficient numbers to average the effect. kWh are only ever used as a proxy for demand.
- 6.2 GPU operates a common use of system charge policy across our area, with prices differing according to voltage of connection and contribution to maximum demand of a customer class rather than geographic location. We consider that for the vast majority of customers this is appropriate and provides significant economies on billing and administration costs. Locational signals are provided through connection charges. For very large customers (greater than 10MVA) site specific DUoS may be appropriate.
- 6.3 GPU continues to construct DUoS charges based on the assumption of asset requirements from GSP downwards. We consider that this principle still remains the most appropriate assumption for the construction of DUoS charges. Many people argue that this is not appropriate since not all electricity flows from the GSP. These arguments do not always recognise that networks are not built for instantaneous flows of kWh, but for the capability to deliver capacity when required to an acceptable level of security. It could be argued that the word 'use' appearing in the term use of system applied to distributors' charges is misleading.

- 6.4 Since August 2000 GPU have charged metering charges separately from DUoS. This has been introduced to be consistent with agent competition. This paper only deals with those costs which remain in DUoS following this split.

**Describe to what extent the methods and principles adopted differ from those set out in the seminal paper by Boley and Fowler (1977)**

- 6.5 GPU has not changed the philosophy underlying the charging for DUoS since privatisation. The main principles of our approach are those outlined by Boley and Fowler and further detailed in the Electricity Council Tariff Formulation Manual (1984). These methods are based on the principle of long run marginal costs (LRMC) which we believe are the most efficient and equitable basis for distribution charges. We use the Distribution Reinforcement Model (DRM, also known as the 500MW model) for the network from GSP to LV and the Minimum Supply Cost model (MSC) for services.
- 6.6 Whilst adopting the principles of Boley and Fowler, GPU has amended the detail to make it GPU specific. We have used historic load research data and, where appropriate, forecast data to derive GPU specific diversity factors, etc. Also the GPU network comprises significantly more 132/11kV transformation than a typical UK distribution network. Accordingly we have modified the DRM to reflect this and some 66/11kV transformation.

**Identify the cost drivers captured within use of system charges**

- 6.7 The principle cost driver for a distribution network is to build a network to provide the capability to deliver the maximum load requirements of the end customers. This can be further extended to meeting these requirements with acceptable security standards. The security standards required to be met by the licence are contained within Engineering Recommendation P2/5. Again ER P2/5 adopts load requirements as its driver.
- 6.8 This principle cost driver can be sub divided further: -

Initial asset requirements: The network must be built to accommodate the requests and requirements (both direct for new connections and via load growth for reinforcement) of the end customers. Whilst the cost of new assets is likely

to reduce with efficiency savings, the purchase cost of existing assets remains fixed.

Load migration: Investment in the network is long term and load migration can leave some assets under utilised. The DRM is a forward looking model and in order to accommodate the above two points a factor, known as the tilt factor, is built in.

Operation and maintenance: Once assets are established they must be maintained and the whole network operated. Over time the costs of these activities may vary with efficiency savings.

- 6.9 For services, the existence of a connection can be as much of a cost driver as the demand requirements due to use of standard sizes of equipment.
- 6.10 In addition to the drivers above, all those costs listed under 'what other activities are also captured in DUoS' can also be considered as drivers.

**Describe how network asset costs are derived, and explain how these costs are hypothecated to customer groups**

- 6.11 Asset costs are based on the assets required to build the network described by the DRM (as localised by GPU). The costs for this model are derived in two ways.
- 6.12 For secondary network costs (11kV and lower) we use the same estimating systems that are used to calculate the cost of any new secondary network scheme within GPU. These systems allow an engineer to build up a scheme and then apply the latest costs to the elements of that scheme. Costs are updated in the system regularly to reflect either what we are actually paying for certain assets, or new contracts for provision of, for example, cable laying. We have standard schemes established in our system to reflect the requirements of the DRM and we revise the costs of these schemes immediately prior to pricing.
- 6.13 For primary network costs the number of schemes we are regularly doing and greater volatility in prices makes the above method erratic. Schemes are established in the same way as above, but latest costs are not always applied.

We review the latest costs we have for various items and then smooth them to remove any volatility due to manufacturing cycles or unusual schemes.

- 6.14 These costs are hypothecated to customer groups using the methods outlined by Boley and Fowler and used within the DRM. The principles used by the DRM are to use annuities costs apportioned to customer classes based on coincident factors for those classes at each voltage level. The model has seven levels of system (five for direct 132/11kV transformation). Each level of the system is considered independently and then added together.

**Explain the main elements of, and activities associated with, network operating and maintenance costs. Outline how these costs are calculated and then hypothecated to different customers**

- 6.15 The principle activities associated with network operating and maintenance charges are the repair and maintenance of network assets, including overhead and underground cables, switchgear, transformers, operational buildings and associated tools and workshops. In addition the charges include control and incident management, system operation and system data management.
- 6.16 These costs are applied to DRM cost on a flat basis applied across all assets included in the DRM.

**Describe how the costs of electrical losses are treated**

- 6.17 The principle cost resulting from losses is the cost of the energy. Suppliers are required to demonstrate that they have supplied sufficient units on to the network to meet these losses. This is achieved by the use of loss adjustment factors and does not in any way affect, nor is included in, DUoS charges.
- 6.18 As losses exist, it is necessary to increase the size of some assets on the network to transport units which will be lost further into the network. It is this aspect of losses which is included directly within DUoS charges and is achieved by using appropriate loss factors within the DRM.

**Identify what other activities are also captured in use of system charges.**

**Outline how other costs are hypothecated to different users.**

6.19 Other costs included in DUoS: -

Business rates: Currently built into the DRM based on capacity. We anticipate reviewing this as the new rating methods are introduced.

NGC exit charges: Are included in the unit rate of all tariffs. Charges are derived from using peak coincident factors (assuming that NGC connection assets are determined by coincident peak demand on GSPs), and scaled uniformly to the level of total charge advised by NGC.

Overheads: Are included within the MSC which relates to the standing charge.

Working capital, included as an adjustment.

**How these methods and principles are modified to ensure compliance with the distribution price controls.**

6.20 The DRM and MSC produce yardstick charges. These yardstick charges are then scaled to ensure our total revenues are within those allowed by the Distribution Price Controls. Currently scaling factors are less than 100%, i.e. the LMRC 'model' income requirements are greater than the target income GPU raise from use of system charges within the price cap ceiling.

**Describe the sensitivity of network costs to changes in demand**

6.21 In the previous price control review, the revenue driver in the price control formula was changed from kWh only to a 50:50 split between kWh and pre-determined customer numbers in order to 'remove any artificial incentive on the PESs to increase the use of electricity...'. This driver was retained at the last price control. This split better reflects the true cost drivers of the distribution businesses whilst retaining commercial incentives on businesses to 'seek out and meet the needs of their customers'. The sensitivity of network costs is affected by a number of factors: -

Coincident factors: An increase in demand by an end customer will only impact on network requirements to the extent it is coincident with the maximum demand on that part of the network.

Utilisation: Assets can be under utilised for two principle reasons. Firstly use of standard size equipment results in 'spare' capacity being available in parts of the network. Secondly load migration results in assets which have been utilised becoming under utilised. Some increase in demand requirements is often satisfied from use of this 'spare' capacity.

ER P2/5: An increase in demand may result in additional reinforcement due to a higher class of security being required to meet ER P2/5.

Customer costs: Where a new small customer is connected there will always be a certain amount of fixed costs (service etc) irrespective of the actual load required.

**Demonstrate what proportion of connection costs, if any, are recovered through use of system tariffs**

- 6.22 Connection charges to new customers reflect the offsetting of future DUoS revenues against connection costs. Included in DUoS are those assets that are common to discrete classes of user (including MSC costs). Any additional costs that are incurred on account of an individual connection are collected as a capital contribution from the customer. This method helps ensure that individual customers are given locational signals where their connection costs are high and are not subsidised by the general body of customers. Future DUoS revenues are set against connection costs by use of tariff support.

**Identify any changes you envisage to the methods and principles of charging**

- 6.23 GPU is unusual amongst distributors in having a published EHV DUoS tariff. We have continued to do this since the EHV customers we have are not in the main our largest customers, but are EHV because of either remoteness of location or the disturbing nature of the load. Our largest customers are often connected at 11kV. Whilst we can see no changes to the principles indicated for the majority of customers, where we do have very large new customers (say greater than 10MVA) we will consider whether it is appropriate to offer site-

specific terms. This is normally only appropriate where the assets required by the customer can be identified. In these cases many of the basic assumptions made above are still retained, but the boundary between up front (connection) and ongoing (DUoS) charges is considered on a case by case basis after negotiation with the customer. This is made possible by the treatment of DUoS as excluded revenue in these cases. Our ability to offer this is also determined by the willingness or otherwise of our shareholders to invest in these ventures at returns set by the price control. These returns are often well below those anticipated by the newly connected customers for their projects.

- 6.24 Originally all DUoS tariffs 'matched' supply tariffs since both were paid by the same person in the same bill. In the current market, however, there is no need to continue this since the supplier pays DUoS and can incorporate this charge into their charge in whatever manner they choose. GPU adopted this principle sometime ago and now bases its tariffs on non-supplier specific information. One key element now used is profile class. This method allows greater commercial freedom for both suppliers and distributors. In practice it still defines customer groups in familiar classes e.g. domestic, small commercial/industrial, large commercial/industrial etc. We do not believe this minor change moves away from the underlying principles used since before privatisation.
- 6.25 The following factors may also cause us to review the methods used to formulate DUoS charges:
- ◆ Changes in connection rules following the competition in connections consultation.
  - ◆ Developments in embedded generation following Ofgem/DTI working group.
  - ◆ The ability to determine accurately in a cost effective manner the characteristics of a customer from supplier derived information. Without the requirement of a combined supplier/distributor to maintain 2 million plus billing records for end customers, the maintenance of LLF classes for DUoS billing requires careful consideration.
  - ◆ Changes to the calculation of business rates.

- ◆ The cost of purchase and operation of stand alone DUoS billing systems;  
and
- ◆ The availability and accuracy of metering data sourced by the industry  
for common use.

## Appendix 7 Northern Electric (NEDL)

### Introduction

#### *Purpose of this Statement.*

- 7.1 This statement is NEDL's response to Ofgem's request and provides background information used in respect to the setting of the distribution use of system charges for 2000 / 01 that came into effect 1 April 2000.
- 7.2 NEDL is the electricity distribution system asset operator in North Yorkshire and the North East of England.
- 7.3 The statement demonstrates how the use of system charges are derived and in particular:
- ◆ identifies the cost drivers captured within the use of system charges;
  - ◆ explains how other activities are captured in the use of system charges;
  - ◆ describes how the network asset charges are derived and how costs are allocated to different users;
  - ◆ explains the main elements of network operating and maintenance costs and how the costs are calculated and allocated to the different users;
  - ◆ explains how the costs of network losses are treated; and
  - ◆ explains how the principles and methods are modified to ensure compliance with the distribution price controls.
- 7.4 An illustrative example shows how the use of system charge for the standard domestic tariff (credit) is derived.
- 7.5 The statement describes the sensitivity of network costs to changes in demand and information is provided to show to what extent connection costs are recovered through use of system tariffs.

- 7.6 To conclude the statement identifies areas in the methods and principles of charging which NEDL envisages will change to continually develop the distribution use of system tariffs.

*Background*

- 7.7 The principles and methods of charging for use of system which NEDL uses are based on a tariff model developed by the Electricity Association (EA) and have been consistently applied since vesting in 1990.
- 7.8 The methods and principles are broadly those set out in the Boley and Fowler seminal paper (1977).
- 7.9 The main principles applied by NEDL which appear in the Boley and Fowler paper for setting tariffs include recognition of:
- ◆ the load flow from Grid Supply Point (GSP) to connection point;
  - ◆ load research carried out to apportion costs of meeting incremental loads fairly to different users;
  - ◆ fixed and variable elements in the tariffs; and
  - ◆ the effects of plant mix in the asset value.
- 7.10 The yardstick should be reviewed at regular intervals and that when the tariffs are set reflective of the yardstick values.
- 7.11 The use of system tariffs primarily consist of two elements:
- ◆ a daily standing charge; and
  - ◆ a unit based charge.
- Large customer tariffs are additionally subject to a charge to reflect distribution capacity made available to customers.
- 7.12 The daily standing charges reflect the costs of distribution system administration and management.

- 7.13 The unit charges and distribution capacity charges reflect the costs associated with distribution system assets.
- 7.14 Regulatory price control determines an allowed revenue which takes into account other costs associated with managing the distribution system as described in paragraph 7.24.
- 7.15 To take account of the regulatory price control, the tariffs derived from the EA model are adjusted on an even-handed basis.

### **Methods and Principles of Charging**

- 7.16 The model used by NEDL is based upon the Long Run Marginal Cost (LRMC) methodology available at the time of its development and is utilised to model the tariffs to cover costs associated with the distribution system.
- 7.17 NEDL uses the EA developed model known as the 500MW system yardstick model which represents a one sixth scale financial model of the NEDL distribution system.
- 7.18 The model's asset value is not changed by the addition of the incremental load, but it represents in a unit charge the cost of extending the distribution system based upon the average £/kW of the financially modelled distribution system.

#### *Distribution system cost drivers captured in the use of system charges.*

- 7.19 The cost drivers captured in the model derived use of system charges associated with the distribution system are:
- ◆ distribution network asset costs excluding load related system reinforcement and new connections tariff support;
  - ◆ network operating and maintenance costs;
  - ◆ distribution system losses;
  - ◆ transmission Exit Charge costs; and
  - ◆ formula assessed rates.

7.20 Other factors affecting the use of system charges associated with the distribution system are:

- ◆ rate of return on assets;
- ◆ expected life of assets;
- ◆ distribution system diversity and effects of reactive power; and
- ◆ utilisation of distribution system.

*Administration and managerial charges.*

7.21 The daily standing charges in the use of system tariffs recover the overhead costs of running the distribution business.

7.22 Historically the overhead charges have been apportioned according to customer numbers and a metering weighting factor.

7.23 This relativity has changed as a result of unbundling of metering activities and there has been significant movement of costs from the standing charge with the removal of metering costs. To minimise the change in tariffs the standing charges have been reduced in line with unit charges.

*Other activities captured in use of system charges.*

7.24 The following activities are captured within the distribution system charges:

- ◆ capital expenditure for load related system reinforcement;
- ◆ tariff support for new business system expenditure; and
- ◆ data management system costs.

7.25 These charges are applied to different users by scaling the model derived tariffs to ensure the forecasted income remains within the defined allowed income.

7.26 The scaling is based upon the relationship between allowed income and income derived from the tariffs, expected customer numbers and forecasted distributed units.

*Derivation of network asset charges and hypothecation to different users.*

- 7.27 The network asset charges allocated as a unit charge to the users relate to the costs associated to modify the distribution system due the effects of adding an incremental load of 1kW to a 500MW model of NEDL's distribution system operating at full capacity.
- 7.28 The model uses the costs of installing a new distribution system from a green field site scenario which are based upon NEDL's plant and asset values. The model consists of different voltage levels of the distribution system.
- 7.29 The plant and asset values are factored down to the regulatory asset value.
- 7.30 Two types of demand are considered; system maximum demand (SMD) and aggregated maximum demand (AMD) which is the sum of the maximum demands at each of the connection points.
- 7.31 Using the SMD and AMD, the asset charges, which are the plant and asset values annuitised at the rate of return over the expected life of the system, are derived as an average cost per kW.
- 7.32 The annuitised plant and asset charges are allocated to the different users by grossing the cost per kW with the published EA coincidence factors. The coincidence factors define the effects of adding the incremental load at connection points relevant to the different tariffs. The coincidence factors take into account the effect of the impact on each of the higher voltage levels above that of the connected voltage.
- 7.33 The summation of the grossed values represents the annuitised cost to modify the overall distribution system to sustain the additional incremental load as a direct consequence of the additional load.
- 7.34 The coincidence factors and load factors were derived from extensive national research carried out by the EA into system demand and load profiles. NEDL have assumed that characteristics of load have not changed since these figures were published.

*Network operating and maintenance costs.*

- 7.35 NEDL includes within its calculations the following elements associated with network operating and maintenance cost:
- ◆ network repair and maintenance;
  - ◆ non-capitalised planning and construction; and
  - ◆ system control.
- 7.36 The network operating and maintenance costs are represented in the model as a percentage of the regulatory asset value.
- 7.37 This is allocated to the different users in the same manner as asset related costs.

*Distribution system losses.*

- 7.38 An allowance is added to the annuitised cost (paragraph 7.31) which represents the percentage loss on the system from the additional incremental load. The loss allowance reflects the impact of the additional load at the different voltage levels.
- 7.39 The distribution system losses were derived from extensive national research carried out by the EA. NEDL has assumed that characteristics of load have not changed since these figures were published.

*Modifying methods to ensure compliance with distribution price controls.*

- 7.40 The principles adopted by NEDL in setting the use of system tariffs aim to achieve a fair and equitable recovery of allowed revenue across the different users.
- 7.41 Mechanisms do not exist in the 500MW model to adjust the revenue from the derived tariffs to match the allowed revenue resulting from distribution price controls.
- 7.42 The 500MW model is used as a yardstick to show the relativities of the tariffs similar to each other and consistency of approach across different users.
- 7.43 The model does not include all costs associated with allowed revenue and the derived tariffs are factored to account for this.

7.44 NEDL scales the model derived tariffs to ensure the forecasted income matches the defined allowed income.

**Example of how the use of system charges are derived for standard domestic tariff (credit)**

7.45 The following illustrative example shows how use of system charges for the standard domestic tariff (credit) were derived for 2000/01.

Standing Charge (network only) 3.1665 pence per day.

Standard domestic tariff (credit)	unit rate pence per unit
System provision	1.0989
Transmission	0.1044
Rates	0.1140
500 MW Model Sub Total	1.3173
Scaling factor at 12.75%	0.1679
Total	1.4852

Where:

- ◆ system provision is the summation of the grossed annuitised rate of return of average cost/kW including the repair and maintenance;
- ◆ transmission is the Exit Charge apportioned to different users;
- ◆ rates are the formula assessed rates apportioned to different users; and
- ◆ scaling factor takes account of the price control.

**Sensitivity of network costs to changes in demand and proportion of connection costs recovered through use of system tariffs**

7.46 The impact on the distribution charges due to changes in distribution system demand is only small.

7.47 The allocation of formula assessed rates is based upon the forecasted distributed units.

7.48 A large increase in distributed units results in a disproportionate reduction of unit charges.

- 7.49 Connection costs are not directly captured in the use of system tariffs. The derived tariffs are scaled to match the allowed revenue and as the allowed revenue allows for capital costs associated with new connections a proportion of connection costs are recovered by use of system charges.
- 7.50 The use of system tariffs incorporates recovery of the tariff support allowance offered to capital new connections.
- 7.51 The average percentage of connection costs funded through the use of system charges has been assessed at 23.8%.

### **Future changes and developments**

- 7.52 NEDL recognises that there is need to overhaul the model to be more forward looking. Tariff setting in the future may take into account the following issues as well as others identified as a result of this review:
- ◆ the balance between connection charges and the use of system charges;
  - ◆ the liabilities and access rights issue may affect tariff setting; and
  - ◆ the facilitation of embedded generation may impact the use of system charges.
- 7.53 Developments which NEDL would like to introduce include of the following:
- ◆ tariffs which reflect the business needs and cost structure of the distribution business, moving away from historically structured tariffs;
  - ◆ principles which set tariffs that use current and future costs rather than being based upon historical costs;
  - ◆ develop a tariff setting model which more closely reflects the impact of changes in demand on the distribution system; and
  - ◆ adopt methods to more closely reflect the price controls.

## Summary

- 7.54 NEDL's use of system charges recovers fairly and equitably the allowed revenue from the different users. Tariff setting methods and principles should be developed to reflect the changes in the industry and be adopted by the electricity distributors to provide a greater consistency.
- 7.55 The methods and principles for setting use of system tariffs within NEDL have been consistent since vesting. However NEDL recognises that there is a need to overhaul the model to be more forward looking and that a fundamental review of the process of tariff setting is introduced.
- 7.56 NEDL welcomes the review from Ofgem and is keen to participate in any fundamental review whether carried out on an individual basis or working in a national group.

## Appendix 8 NORWEB

### Methods and Principles of Charging Distribution Use of System

- 8.1 Norweb aims to set Distribution charges to recover the revenue allowed to us by Ofgem in their Distribution Price Controls.
- 8.2 We aim to recover this revenue from the various tariff groups in proportion to our allocation of costs as predicted by our network-pricing models. These models aim to recover two main categories of cost.
- ◆ The marginal customer related cost is the cost of providing the minimal local system required to provide a continuous connection to satisfy our system security standards. This is represented through the customer service model.
  - ◆ The network related cost aims to recover the capacity related cost of building and maintaining the plant needed to meet incremental system demands. This is represented through the 500MW model.
- 8.3 It has been widely accepted that the most appropriate way to allocate costs for tariff setting is to use the long run marginal cost, which provides an economically efficient and stable pricing structure. It was for these reasons that the government advocated its use in the utility industries since the 1970's. The seminal work by Boley and Fowler set out the principles for its use within the Electricity industry and for electricity supply tariffs in particular. A small part of these principles contain guidance on distribution network pricing.
- 8.4 In 1984 the Electricity Council produced their Tariff Formulation Manual as a practical guide to tariff makers on the principles and application of the long run marginal cost tariff structures proposed by Boley and Fowler. The manual contains the principles and practical examples of how to set charges for use of the network, based on the costs of meeting an increment in demand rather than relating the charges to the actual year-by-year expenditure on network engineering. The manual differs from the seminal paper in that in order to improve cost reflectivity, the costs of the intermediate voltage level are identified separately with recommendations of appropriate coincidence factors. The

model proposed by the manual has then been enhanced to reflect the design and construction policies employed in our area and the range of tariffs on offer.

- 8.5 In 1998 EA Technology produced the Electricity Association Cost Allocation Spreadsheet (eaCASS) model. This was produced at the request of several distribution businesses forming the membership of Module 6 of the Strategic Technology Programme. The new spreadsheet aims to formalise the Electricity Council Tariff Formulation Manual in an easy to use, logical format. Additional features were added at the request of the distribution businesses to allow the reflection of the differing asset lives expected of the range of assets employed. The eaCASS model encompasses the principles of the 500MW and customer service models.
- 8.6 The method of long run marginal costing, as proposed in the tariff formulation manual and used in the eaCASS spreadsheet, is implemented using, what has become known as the "500MW model". The name stems from the fact that it calculates the cost of an increment of 500MW of maximum demand at each voltage level of the distribution network. 500MW is chosen as the increment as it is the smallest increment which allows an accurate reflection of the range of asset configurations used within our distribution network even at the highest voltage level. The model also includes a range of both rural and urban networks aimed to reflect the current range of new connections projects giving rise to incremental load on Norweb's network. However, the model is not used to determine a geographic split of prices. No rural/urban distinction is made in the DUoS tariffs, in line with the commitments made by the electricity industry to the Secretary of State at the time of privatisation in 1990.
- 8.7 The 500MW model then aims to convert the capacity related cost drivers into units that can be practically measured using the standard metering systems in place. Costs of traditional metering systems dictated that these record only kWh unit consumption in smaller supplies such as domestic & small commercial but include maximum demand, kW/kVA for larger industrial supplies.
- 8.8 The main steps in the production of the final tariff unit prices are:
- i) establish the capital costs for 500MW at each voltage level in the network

- ii) these costs are then annuitized using the latest rate of return allowed on our assets, an annuitized operation and maintenance factor related to capital expenditure and assumed asset lifetimes as issued in the latest code of practice documents giving a £/kW for each voltage;
- iii) these figures are then used to derive a unit cost yardstick for each tariff group, dependant on their distinctive consumption characteristics as derived from past national load research;
- iv) a contribution towards NGC Exit charges and local authority rates are calculated by dividing the forecast NGC Exit and local authority rates charges by the forecast system maximum demand to give a £/kW cost in the same way as the network model costs. This is then applied to each tariff group in line with its expected load factor;
- v) these yardstick costs are then combined with forecast volumes and an expected revenue figure is calculated;
- vi) this is compared with the regulated allowed revenue figure and scaled up or down to achieve the allowed revenue figure.

8.9 The operation and maintenance factor reflects the annual costs of operation and maintenance (O&M) activities as a proportion of our regulated gross asset valuation. The factor is added to the annuitisation factor derived from the rate of return and the expected asset lives. The O&M factor recovers the cost of system operations and control and the regular repairs and maintenance costs of planned and emergency work. These costs are treated as general network costs rather than customer type specific or voltage level specific and therefore the costs of operation and maintenance are spread out over the whole range of assets in the 500MW model and are apportioned to customers in proportion to their use of the system.

8.10 In allocating the cost of each voltage and transformation level in the system, a factor is included for the losses associated with measuring 500MW at that stage of the network. These factors are derived from Norweb's published loss adjustment factors. These are, in turn, calculated from the difference between Grid intake plus embedded generation and metered unit sales and are allocated

across the voltage baskets to reflect the level of use of our system on losses at each voltage level.

- 8.11 The 500MW model attempts to calculate the network costs due to incremental unit of demand. It assumes that there is no generation embedded in the ideal network. The localised network costs (or in theory at least, benefits) of having generation within our network are passed on in either higher or lower generation connection charges.
- 8.12 The customer service model only recovers the cost of a minimum connection, comprising of typical service assets such as service cable and termination equipment plus a proportion of the low voltage network. Any additional costs over and above the minimum are collected in the form of a capital contribution to the connection costs at the time of service connection installation.
- 8.13 In addition to network costs, the cost of use of system billing and meter asset provision are also recovered through distribution tariffs. They are recovered as part of the standing charges as the costs are wholly customer related. The cost of billing encompasses both capital and operating costs, and is allocated based on the particular billing systems used for that particular customer group.
- 8.14 Meter asset provision charges recover both the annuitised capital costs of the meter and the operational cost involved in recording the details of the meter. Customers who chose not to use our meter asset provision service are allocated a different use of system tariff with reduced standing charges. Meter asset maintenance charges are based on activity costs & volumes and are charged for on a transactional basis. The transactional charges cover the costs of providing the service activity including an allocation of the appropriate IT system costs.
- 8.15 As the network-pricing model is, in itself, based on incremental cost, it already reflects accurately the change in network costs as they are affected by changes in system maximum demand. However, it does not attempt to reflect the costs of “churn” and movement of customers within our area that can lead to localised increases in demand without affecting the overall level of demand at the grid intake level. This can result in a level of theoretical stranded assets and maintenance cost which cannot be recovered through use of system pricing.

- 8.16 The network-pricing model aims to recover all the cost of the minimal cost connection excluding that recovered through capital contributions. Where the cost of a new connection aims to recover the same element of cost, a capitalised tariff support allowance is given in respect of the expected use of system tariff income.
- 8.17 Whilst the model, in its current form, may not be ideal in reflecting the needs of the more mixed load and generation found in modern networks it does provide a robust and stable platform for producing Use of System pricing in line with the current Regulatory formula, as the current formula also ignores the effect of embedded generation. At a cost, extra complexity could be introduced to the model with the aim of greater cost reflectivity, but the effects of the allowed revenue scaling will generally have the effect of reducing the benefits of the extra complexity. The distribution use of system tariffs are levied on suppliers who in turn develop their own customer specific tariffs. It is questionable how effective pricing signals in the DUoS tariffs are, when suppliers may modify these structures to meet their own marketing needs e.g. removal of customer standing charge from some suppliers' customer tariffs whilst DUoS tariffs still contain this element.

#### **Illustrative Example for the Standard Domestic Unrestricted Tariff**

- 8.18 Network capital costs were obtained from our asset adoption evaluation-estimating package for the 500MW system.

Network Level	Valuation
132kV network	£18.892M
132/33 transformation	£16.245M
33kV network	£33.182M
33/11kV transformation	£33.607M
11kV network	£82.270M
11kV/LV transformation	£60.023M
LV network	£39.612M

These costs are annuitized to reflect the latest allowed rate of return, annual operation and maintenance factor and assumed lifetime of the assets in each costing line.

Network Level	Annuitized £/kW
132kV network	£4.62
132/33 transformation	£3.67
33kV network	£5.82
33/11kV transformation	£5.96
11kV network	£14.13
11kV/LV transformation	£7.54
LV network	£4.68

Forecasts of customer numbers and annual consumption were obtained for Domestic Unrestricted

Customer numbers	1,843,387
Annual Consumption	6338.9GWh

Standing data on load research is then used to ascertain the cost on each stage of the network due to a domestic unrestricted customer

Power Factor	1.00
Load Factor	3500kWh/kW
Upper Coincidence Factor	0.925
Lower Coincidence Factor	0.983
Domestic LV mains Factor	60%

The resultant network costs

Network Level	p/kWh
132kV network	0.122
132/33 transformation	0.097
33kV network	0.154
33/11kV transformation	0.157
11kV network	0.373
11kV/LV transformation	0.212
LV network	0.079
TOTAL	1.194

NGC Exit charges and local authority rates are calculated by dividing the forecast NGC Exit and local authority rates charges by the forecast system

maximum demand to give a £/kW cost. This is then divided by the kWh/kW factor to produce a p/kWh.

NGC Exit Charges	0.11p/kWh
LA Rates	0.08p/kWh

Giving a resultant unit price yardstick of 1.39p/kWh.

- 8.19 The customer related standing charges are then calculated. Capital costs of the service and a proportion of the LV mains are obtained from the asset evaluation and annuitised over the expected life.

	Capital cost	Annuitized Cost
Minimum Domestic service cost	£251.50	£7.82
40% Mains recovered in Standing charge	£120.80	£3.76

Meter provision costs are calculated by taking the current capital cost of purchasing the meter, annuitising the cost over the lifetime of the assets to produce the latest accepted rate of return. Costs for IT are included to produce an annual cost on a similar basis to the service and network costs.

Meter Asset Provision annual charge	£2.63
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A contribution to the IT and operational cost of billing Use of System charges to suppliers of domestic unrestricted customers is added

Annual cost of Billing	£0.32
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This produces a yardstick standing charge of £14.53 per year.

- 8.20 Forecasts of unit sales, losses, RPI, interest rates, under/over recovery is then input to the regulatory formula to forecast the Regulated Allowed income for 2000/1.

8.21 A forecast of the volumes and income arising from Regulated transactional charges is then made. The difference is the revenue allowed to be recovered from Use of System tariffs.

8.22 The revenue expected from charging both yardstick standing charges and unit rates is calculated and compared with this and both Unit and standing charges are scaled up or down to match the allowed revenue.

	Yardstick	Revenue	Allowed	Scaling factor	Published rates
Standing charge	£14.53 p.a.	£26.78M	£24.63M	0.92	£13.36 p.a.
Unit rates	1.39p/kWh	£88.12M	£72.26M	0.82	1.14p/kWh

## Appendix 9 SEEBOARD

9.1 This statement describes how SEEBOARD derives the published Use of System tariffs that apply to aggregate customer groups supplied at voltage levels below 33kV. Our approach entails initially formulating costs at a tariff level and then hypothecating these into tariff charges that reflect price controls at a tariff 'basket' level. A similar approach is taken for site-specific charges, except that these are modelled on an individual basis to take account of the specific connection assets and specific connection charges applicable at the time of installation or enhancement.

9.2 The following significant changes were made in setting charges for 2000/1, compared to prior years.

- ◆ The metering charges and the Use of System charges were disaggregated.
- ◆ The residual Use of System charges were rebalanced to take account of the outcome of the Distribution Price Control and to achieve some initial rebalancing of the relationship between standing charges and unit rates undertaken, whilst mitigating intra-customer class disturbance effects.
- ◆ The LV monthly tariff was split between half-hourly and non-half-hourly metered installations to reflect differences in usage of assets and network demands between the two groups.

### *Comparison with the Seminal Paper by T A Boley and G J Fowler*

9.3 We continue to apply the principles contained within the paper to Distribution Use of System charges, as set out below.

- ◆ Distribution costs are generally demand related and, within tariffs, are analysed into annual capital charges of reinforcement at defined voltage levels. Capital charges comprise depreciation and return on new investment, based on a 40-year amortisation, and allowance is made for operation and maintenance costs (including labour, other costs, rates etc).
- ◆ Account is taken of the effect on the distribution cost structures of the coincidence that a customer/tariff group may have in contributing to demand at each voltage level on that network.

### *Key Principles in Setting Tariff Structures and Charges*

9.4 The following principles are taken into account when making material changes to either the structure or the level of Use of System charges.

- ◆ Avoidance of undue discrimination between customer classes (Electricity Act 1989 obligation):
- ◆ We use the yardstick models that apportion network reinforcement costs in an equitable manner across tariffs, having regard for the effect of customer coincidence on network demand.
- ◆ Equitable treatment of all suppliers and avoidance of distortion of supply competition (Licence and Use of System Agreement obligation):
- ◆ We apply the same Use of System Agreement to all suppliers and ensure common publication of changes to all suppliers.
- ◆ Avoidance of unduly complicated tariff structures:
- ◆ We aim to set simple pricing structures and to include additional elements only where necessary, to deliver underlying cost messages.
- ◆ Capability of tariff structures to be metered, billed and validated by suppliers.
- ◆ We set tariff structures that are capable of being metered and/or billed using either information available from the metering equipment currently installed at a customer's premises, information available from accredited agents, the electricity settlements system or other appropriate data flows. We aim to ensure that suppliers can validate invoices from normal industry data flows and that sufficient notice is given of any changes, to allow suppliers to adjust their validation processes as necessary.
- ◆ Alignment with regulatory price controls:
- ◆ The revenue stream derived from yardstick models, based upon long run pricing principles, is scaled as necessary to align with annual price control allowances. Whilst avoiding major disturbances across tariffs in the short term, we aim, over time, to reach a position where the costs on a tariff basket approach align with the structure used to set price controls and for tariffs to remain broadly cost reflective.

## *Load Research – Coincidence of Customer Demand*

### **The network is categorised as follows:**

- ◆ 132kV network
- ◆ 132/33kV substation
- ◆ 33kV network
- ◆ 33/11kV substation
- ◆ 11kV network
- ◆ 400V (low voltage) network

- 9.5 Coincident contribution to demand, measured in kW, is described for each category above and for each of the primary time periods within each of the published Use of System tariffs.
- 9.6 The coincidence factors are taken from the Electricity Council Load Research papers published in respect of 1989/90. There is no evidence that there has subsequently been any significant deviation from the data gathered in that exercise.
- 9.7 Assumptions are taken on load factor for tariffs. These are based upon demand and unit consumption from monthly read sites and unit consumption for quarterly metered tariffs. This issue is important. Although demand is the key cost driver, the majority of customers do not have demand-recording meters. Tariffs are therefore based on measuring kWh of consumption rather than kW of demand, and a translation from load research demand information to consumption is made.
- 9.8 Public lighting is assumed to follow a dusk to dawn operating regime.

### *Primary Cost Drivers in Tariff Derivation*

#### **a) Network Reinforcement Costs**

- 9.9 The network reinforcement costs are assessed by using the 500MW Model to estimate the marginal cost of an increase (or decrease) in demand (sometimes referred to in the Fowler/Boley paper as the reinforcement cost). The 500MW model is a description of how SEEBOARD's existing, mature distribution system would be extended to accept an additional 500MW at each voltage and

transformation level (as defined above) using today's practices and costs. It is not a 'green field' model.

- 9.10 Criteria will differ at each voltage level according to the percentage and length of underground cables and overhead line installations, the number of transformation points necessary to support the load and the extent of back-up circuits.
- 9.11 The resultant costs are described in terms of £/kW of system (simultaneous) and aggregate maximum demand for each voltage level. Tariff group demand is assumed to contribute totally and fully to the aggregate demand at the voltage of connection. The diversity of demand across tariffs is attributed to the next voltage level up.

**b) Percentage Loss Factors**

- 9.12 The 500MW model specifically assesses the costs of 500MW at each voltage level. In order to assess total reinforcement costs attributable to any tariff group, it is necessary to accumulate all of the relevant network assets from the point of connection with the National Grid down through the voltage levels and transformation points to the tariff point of connection. The appropriate loss factors used are those occurring at the time of System Maximum Demand and are simply applied to the level of reinforcement costs to recognise that additional assets are required at a higher voltage level to meet a kW of demand at a lower voltage level. They are not the loss factors (which vary by time of day and season) used for the determination of supplier purchases for electricity sales.

**c) Annuity Factors**

- 9.13 A capital annuity factor is derived to recover an annual contribution towards the costs described in section a) above.
- 9.14 This factor is based upon:
- ◆ the period over which the capital charge is recovered;
  - ◆ a rate of return on capital of 6.5%; and
  - ◆ the operations and maintenance costs (expressed as 2.25% of the long run marginal capital cost to meet a kW of demand).

#### d) Apportionment Factors

- 9.15 Published tariffs assume that a customer is supplied at either low voltage (230/400V nominal - LV) or at high voltage (below 33kV - HV). Apportionment factors distinguish between LV and HV and, as described in section 2.4.1, build on the assumption of contribution either to aggregate load at the voltage of supply or diversified system maximum demand at the next voltage up. They are further used in the derivation of the available capacity charge that is applied to tariffs where meter readings are normally taken on a monthly basis.

##### *Annual Reinforcement Costs Per Tariff Expressed as a PPU*

- 9.16 This step (in two parts) translates yardstick load and reinforcement costs into the unit-related elements of each tariff. A Minimum Supply Cost Model is separately used to develop the low voltage standing charge (see explanation of the process in section 2.7 below). Low voltage network costs are divided by two on the basis that, currently, this Minimum Supply Cost Model would normally seek to recover 50% of the LV mains costs through the standing charge.
- 9.17 Firstly, the annual reinforcement costs are derived for each voltage level by multiplying together network costs, annuity factor, scaled for losses (as described in sections 2.4.1–2.4.3 above) and using £/kW of system maximum demand or aggregate demand (as further defined by the apportionment rules).
- 9.18 The resultant annual reinforcement costs are then multiplied by the relevant coincident factors (as described in section 2.3) and converted into a pence per kWh cost for each published tariff and unit band.

##### *Calculation of Yardstick Available Capacity Charge*

- 9.19 Capacity charges are applied to monthly metered, LV and HV tariffs. Yardstick charges are derived from the product of network reinforcement costs, annuity factor, relevant apportionment factor, coincident factor and inflated for losses. The resulting charge is applied on the basis of £/kVA of individual customer, required capacity. The yardstick model produces a higher capacity charge for HV supplied customers compared to LV supplied customers. This is due to the attribution of duplicate network asset costs at high voltages.

### *Calculation of Yardstick Standing Charge*

- 9.20 It has been necessary to introduce some change this year into the derivation of this element of tariffs to take account of the effect of disaggregating metering and residual Use of System charges. In prior years, differing metering costs have driven differences in standing charges, particularly across quarterly metered tariffs. Having now fully separated these elements, SEEBOARD took the view that the costs represented through standing charges - namely reinforcement costs associated with service connection and local low voltage mains costs - were not materially different across relevant tariffs. SEEBOARD has therefore equated all quarterly metered primary tariffs.
- 9.21 The approach taken initially considers the current cost of providing low voltage mains and services to 20 domestic properties. Taking a minimum cost, we assume that no further upstream reinforcement is immediately necessary. Capital costs are then annuitised in line with the same assumptions taken in section 2.4.3. This approach remains consistent with the derivation of a tariff support allowance, which will have the effect of reducing the nominal connection charges. By adopting this approach, we seek to align the costs paid by suppliers of new and existing customer connections in Use of System and avoid separate and more complex tariff arrangements. We take account of the ongoing Use of System income when setting tariff support.

### *Derivation of Use of System Charges – Alignment with Distribution Price Controls*

- 9.22 The above processes culminate in a set of tariff charges based upon historic coefficients from load research information converted into coincidence factors of network demand by voltage level and a yardstick model approach to design and investment in network reinforcement. The principles of tariff support ensure no duplication of costs between connection charges and Use of System.
- 9.23 However final tariff setting, rather than reflecting “long run cost plus”, is based on recovering income per year in line with a regulatory allowance defined in the price control formula. Forecasts of customer numbers and consumption are used to calculate revenue from both the price control formula and yardstick models. The yardstick income for each tariff basket is then scaled back by the percentage

difference in the total revenue calculations and adjustments made for the estimated under/over recovery position at the current year-end.

- 9.24 Assumptions may need to be made for RPI and NGC exit charges, depending on the time at which future tariffs are being calculated.

*Illustrative Example for Standard Domestic (Credit) Tariff*

- 9.25 The tables in the example below illustrate the conversion of theoretical yardstick costs for a standard domestic customer to final tariff rates:

The first table is derived from the annuitisation of the 500MW Network Model costs multiplied by the relevant coincidence factors at each voltage level and apportioned by the kWh/kW conversion ratio.

**Table 1 - Calculation of the 500 MW Day Tariff PPU by Voltage Level (p/kWh)**

	Standard Domestic	
Load Factor	37.9%	
kWh/kW Conversion ratio	3,320	
132 kV Network	0.400	
132/33 kV Substation	0.114	
33 kV Network	0.295	
33/11 kV Substation	0.140	
11 kV Network	0.438	
11/0.4 kV Substation	0.152	
0.4 kV Network	0.125	
<b>Total Tariff PPU</b>	<b>1.664</b>	

This second table is derived from a 'Minimum Connection Cost' based on the average costs of connection made to a group of typical domestic dwellings, including part of the cost of the LV supply cable. The original model included the costs of meter provision. This is now netted out.

**Table 2 - Calculation of Yardstick Domestic Standing Charge**

Component	£	Comment
Attributed LV mains and services	13.16	
Idle Service	0.22	
Idle Service Meter <sup>1</sup>	0.23	
Customer Service	3.84	
DuoS Billing	0.52	
Operating & Maintenance Costs – Metering <sup>2</sup>	8.27	
Operating & Maintenance Costs - Service/LV Main	0.00	
Energy Consumption of Meters	0.73	
<b>Total Annual Standing Charge</b>	<b>26.97</b>	To table 3
<b>Total Annual Standing Charge, less metering costs</b>	<b>18.47</b>	To table 4 – total standing charge

- 1 Balance remaining after deduction of published Meter Provision charges – deemed to be within Use of System. As competition in metering progresses this is likely to reduce to zero.
- 2 This component is now included within the separately published Meter Asset Maintenance charges

**Table 3 - Calculation of the 500 MW Theoretical Required Revenue**

	Standard Domestic	Comment
Day Units - p/kWh	1.664	From table 1
Standing Charge £/annum	26.97	From table 2
MP Charge £/annum	2.08	
MM Charge £/annum	3.47	
Day Units - GWh	4,849	
MPAN Numbers	1,215,468	
Day Unit Revenue - £m	80.69	
Standing Charge Revenue - £m	32.78	
MP Charge Revenue - £m	2.53	
MM Charge Revenue - £m	4.21	
<b>Total 500 MW Yardstick Revenue - £m</b>	<b>120.21</b>	

9.26 The theoretical revenue (derived from the 500MW model, the minimum connection cost model and metering charges) for each tariff is then compared to the Regulated Revenues derived from the price control formulae for the forecast year. The theoretical revenue is then scaled to meet the regulatory revenue. The metering charges are not scaled – these represent a competitive market. The fixed (or standing charge) element is not scaled as the majority of this cost is directly or indirectly under the direction of the customer (e.g. the customer can

determine the position of the service cable). The balance revenues, i.e. that part of the network which the customer cannot directly influence, is scaled to meet the financial (regulated revenue) target. The mechanism is shown below.

**Table 4 - Derivation of Standard Domestic Tariff**

Scaled Regulated Revenue (derived from relevant basket in price control)	=	64.59	£m
Fix Total Standing Charges p/MPAN/day (from table 2 ÷365)	=	5.06	
Published Meter Operator Charge p/MPAN/day	=	1.52	
Therefore Network Fixed Charge p/MPAN/day	=	3.54	
MPAN Numbers	=	1,215,468	
Therefore Fixed Revenue	=	22.45	£m
Therefore Variable Revenue	=	42.14	£m
Units Distributed	=	4,849	GWh
Therefore Calculated Unit charges	=	0.869	p/kWh
Round to $\frac{1}{100}$ <sup>th</sup> of a penny and set charge	=	0.87	p/kWh

*Potential Future Changes in Methods and Principles of Charging*

- 9.27 Going forward, we expect to adjust standing charges, particularly for quarterly tariffs, so that they more closely reflect both underlying costs and Ofgem's conclusions in the recent Distribution Price Review.
- 9.28 The anticipated increase in embedded generation and CHP schemes, particularly at the lower end of the market, may also impact future charging principles.

## Appendix 10 Southern Electric

### 1. Introduction

- 10.1 Southern Electric's (SE) Distribution Use of System (DUoS) charges are composed of some or all of the following components: a fixed charge per month or day, an availability charge based on kVA capacity and unit rates based on kWh.
- 10.2 The methods and principles adopted for DUoS charging can be described as representing both a development and modification of the original principles outlined by Boley and Fowler. These principles are based on the concept of Long Run Marginal Cost (LRMC) pricing which is considered to be an efficient and equitable basis for charging. The DUoS charges are designed to recover the appropriate level of costs in a manner which reflects the way in which they arise, avoiding price discrimination and promoting the efficient use of distribution assets.
- 10.3 We operate a common use of system charging policy across our authorised area, with prices differing predominately according to voltage rather than geographic location, constructing charges from the GSP level rather than seeking to identify the electricity flows. The methodology provides correct cost messages for the distinct groups of customers identified in our pricing model. With the exception of large customers with site-specific connections for whom specific charges may apply, the common pricing approach is considered appropriate for the majority of customers.
- 10.4 The costs associated with providing distribution services are segmented into demand related costs, kWh-related costs, and customer-related costs (which do not vary with demand). This analysis of costs, combined with the identification of what drives those costs and contribution of different customer groups to those cost drivers (as derived from load research) helps apportion costs among customers and enables the construction of the charges themselves (fixed and variable components). This approach represents an equitable allocation of costs among customers according to the burdens they impose on the system. The

charge structures indicate how their use of the system contributes to the costs of providing a distribution network.

- 10.5 The methodology for the hypothecation of demand related distribution costs is reliant on load research data. The format of this data has gradually evolved over the years since privatisation to reflect the changing trading environment (e.g. use of standard load profiles)
- 10.6 The Boley and Fowler principles in respect of determining the network asset charges uses a 500 MW model designed to reflect the distribution system. The purpose of the model was to produce realistic costs to be included in the tariff yardsticks. The network losses are accounted for in the design of the 500MW model. A distribution system model with 500 MW Simultaneous Maximum Demand (SMD) should allow sufficient variation within the model to represent a realistic combination of load types. In line with this approach a 500 MW model was developed by SE but in response to the changing trading environment the way in which it produces network capital cost yardsticks differs from the original template model.

## **2. Methodology**

- 10.7 The original Boley and Fowler methodology being a LRMC approach was used to produce costs at each voltage level for a kW of incremental load. This total capital cost was then converted into an annual charge by an annuity factor which included a target rate of return, an allowance for obsolescence and Repair & Maintenance (R&M).
- 10.8 The model as used by SE is updated periodically and costs for each voltage level produced. These costs act as an allocative mechanism to spread the depreciation and the allowed income on the assets across the voltage levels of the network.
- 10.9 In respect of the hypothecation of network costs to customer groups the original Boley and Fowler principles have been modified in SE's cost model. Our approach was to modify the costing model so that the allocation is now based on contribution to annual total demand in respect of R&M costs and winter weekday demand in the case of capital cost. This more cost reflective allocation

demonstrates that it is not just the peak demand on the system that leads to maintenance and reinforcement expenditure.

- 10.10 The main elements of R&M expenditure are split as required between those that are customer related and those that are driven by the level of demand on the network as a whole. The customer related costs include meter operation and a proportion of LV mains and services. The part of R&M driven by demand accounts for the costs relating to operational premises, communication costs and any residual elements of the LV network costs. In 2000/01, the metering charges have been disaggregated from the DUoS charges to facilitate competition.
- 10.11 The R&M costs at voltage levels above LV and part of the LV mains are considered to be demand related and hence recovered through unit rates and, depending on the voltage of connection, through an availability charge. These costs are allocated, at each voltage level, across the customer groups in proportion to that group's share of the demand on the network for the year as a whole.
- 10.12 The remaining non R&M customer related elements (principally providing emergency and non-emergency services) are then allocated in an appropriate manner between the customer groups.
- 10.13 The majority of the corporate overhead costs are apportioned between network activities and the customer service elements, a small residual component being recovered through unit rates.
- 10.14 The fixed (standing) charge yardsticks reflect the customer related costs and contribution to the costs of the local network (the tariff support allowance). In the case of larger customers, the costs of some local network is recovered through the availability charge.
- 10.15 National Grid Company Connection charges are treated as a pass through cost and are recovered according to the contribution to SMD of each customer group, and generally recovered through unit rates.
- 10.16 In cases where site-specific use of system charges apply, they are determined in a manner similar to the principles for standard use of system charges.

- 10.17 The DUoS income derived from the model is then compared with the allowed income implied by the distribution price control formula. A scaling process, if necessary, is then undertaken to ensure the forecast income recovered is consistent with that allowed.
- 10.18 The incidence of electrical losses on the network are reflected in the calculation of loss adjustment factors (LAF's) for the various voltage levels. The cost of these losses are not borne by the distribution business (there is of course an incentive in the distribution price control to reduce losses) and are passed on to be recovered by the supply businesses.
- 10.19 With respect to the impact on network costs of changes in demand this sensitivity is dependent on a number of factors including when during the year the change in demand occurs, and the split of the load amongst the customer groups at that time.
- 10.20 The general principle in regard to connections is that where the cost of extending the network to connect new customers exceeds the tariff support allowance then the balance is recovered as a connection charge. This sends correct cost signals to the customer when he is making a locational decision.

### **3. Future**

- 10.21 Since vesting we have developed the costing model to reflect changes in the trading environment as described earlier. At this stage we do not envisage significant changes to our costing model in the foreseeable future. Nevertheless, we will continue to monitor future changes in the trading or regulatory framework that may necessitate refinements to the model to enhance its continuing cost reflectivity.

## Appendix 11 South Wales Electricity (Infralec)

### Introduction

- 11.1 At the macro level, Infralec's use of system charges reflect the capacity that has to be made available in order to meet final customers' demands, and those fixed costs of servicing the customer that are not related to demand. In order to simplify metering and billing systems (and hence reduce overall costs to customers) units (kWh) are used as a proxy for the variable element. The resulting use of system charges incorporate a combination of fixed charges (p/day), capacity charges (£/kVA) and unit charges (p/kWh).
- 11.2 Use of system charges are differentiated by voltage of connection and customer class, reflecting the differing asset requirements to meet their needs. Infralec does not have geographically differentiated use of system charges. Charges for customers connected at extra high voltage are calculated on a site specific basis reflecting the specific assets employed.

### Methods and principles of charging

- 11.3 The method and principles of charging are essentially unchanged from those set out in the Boley and Fowler (1977) paper, which set out to establish yardstick costs for classes of customer through the use of load research data and the costs of network reinforcement (the Distribution Reinforcement Model). This yardstick approach results in the long run marginal cost attributable to various customer classes, ideally charges should be set at the long run marginal cost for economic efficiency.
- 11.4 The Distribution Reinforcement Model (DRM) has been enhanced by Infralec to include additional elements representing the asset types and configurations employed in Infralec's authorised area e.g. 132/11kV transformation, the 66kV network as well as the 33kV network.

### Cost drivers captured within use of system charges

- 11.5 The principal cost drivers within the use of system charges are twofold: the need to modify and extend the network to meet customers changing requirements, and the need to operate and maintain the network at acceptable standards of

security of supply. The charges also recover the other costs of a distribution business, such as cumulo rates, customer related costs (e.g. registration services and billing), and NGC exit charges.

### **Derivation of network asset charges and the hypothecation of these costs to customer groups**

- 11.6 Infralec's regional DRM is used to derive £/kW reinforcement costs on a Modern Equivalent Asset (MEA) basis. Asset charges are set as annuities based on 40 year asset lives to cover both the costs of depreciation and a return in line with the distribution price control. The charges are hypothecated to customer groups on the basis of the customers' contribution to Simultaneous Maximum Demand. This is achieved through the use of coincidence factors, demand estimation coefficients and average customer consumption in Infralec's area. The coincidence factors and demand estimation coefficients are obtained from national load research carried out by the Electricity Association.
- 11.7 Infralec uses a regional model, disaggregated into four distinct sub-regions recognising network configurations; these are the coastal urban area, the South Wales valleys and two rural areas of Mid Wales and West Wales. These four sub-regions are brought together to form weighted regional averages for network asset charges expressed in p/kWh. It is not judged to be acceptable to set regional tariffs, for example differentiating between rural and urban domestic customers, because of social and other considerations, and for practical reasons of definition and application.
- 11.8 The main elements of, and activities associated with, network operating and maintenance costs and how these costs are calculated and then hypothecated to different customers
- 11.9 Network operation and maintenance covers all those costs associated with the operation and maintenance of the distribution system. These include network planning, system control, information technology, procurement and stores, property and business support, as well as repairs and maintenance.
- 11.10 The costs for operation and maintenance are calculated as a percentage of the network asset value. This percentage is included within the annuity factor

applied to the MEA values at each voltage level in the model, thus the costs are hypothecated to customer groups as set out above.

### **The treatment of losses**

11.11 The network needs sufficient capacity to carry both the electricity used by final customers, and the losses incurred in transporting electricity from the infeeds to customers' terminals. This is accounted for by applying loss percentages at each voltage and transformation level in the model. Suppliers meet the cost of energy losses.

### **Other activities recovered in use of system charges and how they are hypothecated to different users**

11.12 The charges also recover all other costs of the distribution business such as cumulo rates, customer related costs (e.g. registration services and billing), and NGC exit charges.

11.13 Cumulo rates are set by Government on a prescribed assessment and are indexed in real terms on the basis of change in transformer capacity. Infracore includes the costs of cumulo rates on an 80/20 asset/unit basis within the model.

11.14 Standing charge yardsticks are used to hypothecate both customer related costs (costs that do not vary with consumption e.g. customer records, registration and billing), the costs of the service and local network assets across customer groups. For larger customers the costs of local network assets are charged as capacity charges. The costs of distribution metering services (i.e. meter provision and operation, rectification etc) are also included in the standing charge yardsticks.

11.15 NGC Exit charges are recovered according to the contribution to system maximum demand of each customer group, and are generally recovered as a component of the day unit charges.

11.16 Other costs of running the business not recovered elsewhere in the charges (e.g. corporate overheads, administration, and insurance) are included on the same 80/20 asset/unit basis as cumulo rates.

### Application of these methods and principles to ensure compliance with the distribution price controls

11.17 Forecasts of consumption, capacity and customer numbers are applied to the yardstick, which results in the total yardstick revenue. This is compared to the allowed revenue provided through the distribution price control, and a scaling process ensures compliance with the distribution price control. The strict application of scaled yardstick prices could result in high levels of price disturbance for particular customer groups, and moderated longer term judgements have to be made in setting final published tariffs.

### Charges for EHV customers

11.18 Use of system charges for EHV customers are set on a site-specific basis and broadly follow the above approach. The value of assets used to supply each customer and the customer's own consumption details are used to derive the charges. Operation and maintenance, cumulo rates and standing charges all follow the above method and principles. The aggregate revenue from EHV customers is controlled by the requirement to keep within the values indicated to, and used by, Ofgem in setting the current distribution price control. NGC exit charges may be recovered according to the customer's demand on the GSP from which they are normally supplied.

### An illustrative example of how use of system charges for the standard domestic tariff (credit) are derived.

	p/kWh
132kV Circuit	0.215
132/11 kV Transformation	0.034
132/EHV Transformation	0.132
EHV Circuit	0.101
EHV/11kV Transformation	0.029
11kV Circuit	0.230
11kV/LV Transformation	0.255
LV Circuit	0.327
<b>Total DRM cost</b>	<b>1.323</b>
Cumulo. Rates	0.173
Other costs	0.238
<b>Total Yardstick cost</b>	<b>1.734</b>

DUoS charge	1.68
NGC Exit cost	0.11
<b>DUoS charge less Exit</b>	<b>1.57</b>

### **The sensitivity of network costs to changes in demand**

11.19 Changes in demand are brought about by three inter-related drivers; changes in the number of connected customers, migration of demand due to economic activity; and changes in the demand associated with existing customers. The cost of modifying or extending the network to accommodate any of these three drivers is location specific, and can be significant. However, the migration of demand often results in stranded costs. The change in the cost of operating and maintaining the network as a result of any of these three drivers is not significant.

### **Recovery of connection costs through use of system tariffs**

11.20 Distribution use of system charges incorporate the minimum supply costs for the average customer. Connection charges are the excess between the actual costs of connection, plus the future costs of operation and maintenance, for an individual customer and the present value of the revenue within the DUoS charges. This approach provides locational messages to customers, and paves the way for competition in connections through the provision of a level playing field. Use of system charges recover an average of 50% of the cost of connections.

### **Planned changes to the methods and principles of charging.**

11.21 Infracore does not plan to change the method and principles described above in establishing the use of system charges. However, it is planned to simplify the charges by the removal of capacity charges for all customers with non half-hourly metering, the removal of reactive unit charges and the consolidation of the large number of tariffs that currently exist, to the benefit of suppliers and customers.

## Appendix 12 South Western Electricity (Western Power Distribution)

### Methods and Principles of Charging

- 12.1 The principles and methods adopted for setting DUoS prices follow the basis set out by Boley and Fowler. Over the years the detail of the method has been modified whilst retaining the fundamental yardstick methodology for distribution costs.
- 12.2 For example, whilst the Boley and Fowler paper indicates distribution yardsticks based on a three part model of distribution costs (132kV, 33/11kV and 11kV/LV reinforcement costs), the model which has been used for many years follows the revision to the reinforcement cost model introduced in 1983. In this separate costs are identified for each normal level of network and transformation and leads to a model and yardsticks that identify costs at: -
- ◆ 132kV Network
  - ◆ 132/33kV Transformation
  - ◆ 33kV Network
  - ◆ 33/11kV Transformation
  - ◆ 11kV Network
  - ◆ 11kV/LV Transformation
  - ◆ LV Network
- 12.3 The principal cost drivers for use of system are the cost of capital to extend and reinforce for increasing demand on the network and to operate and maintain the network. Network asset costings are based on a 500 MW cost model that incorporates the assets and equipment at each voltage level to support a 500MW increment in Simultaneous Maximum Demand. The quantities in the model, as consistent with engineering planning policy, include assets in proportion to the existing network and are based on equipment available today. It is therefore a Modern Equivalent Asset model.
- 12.4 The main elements and activities associated with network operating and maintenance costs are: -

- ◆ Network Repairs to substations (S/S), overhead lines (O/H) and underground cables (U/G).
- ◆ Network Maintenance to S/S, O/H, U/G and Tree Maintenance.
- ◆ Fault Repairs to S/S, O/H, U/G and Unmetered Supplies.
- ◆ Network Inspection to S/S, O/H, U/G.
- ◆ Network Management to the network (e.g. investigation of voltage complaints and load monitoring)
- ◆ Standby costs for emergency operation and Switching Costs.
- ◆ Dismantling of equipment – S/S, O/H, U/G
- ◆ Materials Costs
- ◆ Network operating and maintenance costs are included within yardstick costs expressed as a percentage of capital at each voltage level in the model. Losses are also applied in yardsticks as a percentage according to the voltage level of the network.

12.5 The fundamental objective of cost allocation across customer classes is to: -

- ◆ Identify the incremental costs of network reinforcement by voltage across the system and express them as a £/kW/annum from the 500MW model described above.
- ◆ Identify the coincidence of the demand of the various classes of customer with system maximum demand.
- ◆ Apportion the incremental costs of the network to customer classes in line with their coincidences to obtain yardstick costs for each class to enable tariffs to be set with the correct relativity of price to underlying cost for all classes.

12.6 The 500MW model is costed at 0.95 power factor so, for customer classes where the normal power factor differs from this, a Power Factor Deviation Cost Adjustment is made.

12.7 Since the removal of standing charges by Western Power Distribution an additional element has been introduced into the unit yardsticks to reflect the LV Service cost elements.

- 12.8 The Miscellaneous Cost element of the yardstick represents the costs of MPAS Operating Costs, Advertising and Marketing Costs and the costs of Bad Debt that are apportioned to all yardsticks on a p/total kWh basis.
- 12.9 Working Capital Adjustments are made to account for the lag between costs being incurred and revenue recovery in the DUoS charges.
- 12.10 Consumer Related Costs incorporate costs such as Customer Records, Service and Billing, Revenue Collection and Corporate Overheads and Administration that are apportioned across customer classes on a weighted customer basis and spread over consumption in each class.
- 12.11 Operational Rates are charged according to total transformer capacity and so are included in yardsticks by apportioning costs across customer classes in line with totals of yardstick elements for transformation and then scaled to achieve forecast total rates.
- 12.12 NGC Exit charges are included in yardsticks apportioning costs across customer classes in line with coincidence at 132kV, and scaled to recover the forecast total Exit Charges for the forecast total consumption.
- 12.13 Yardsticks are used with forecasts of consumption in the tariff charging periods for each class of customer to produce a forecast of total yardstick revenue. Prices are then set for each tariff by scaling the individual yardsticks to meet the target revenue taking into account regulatory entitlement. Where cost movements indicate that price changes to individual tariffs need longer-term adjustment between classes of customer, some judgement is used to ensure that price disturbance to separate tariff is acceptable.
- 12.14 Network capital costs are largely driven by the maximum demand required on the system. Whilst additional capacity on the system is dependent on the physical sizes of equipment that can be installed, overall the use of costing models based on a large sample size, such as the 500MW model, enables the effect of discrete equipment sizes to be smoothed out and incremental cost is well represented by the £/kW values from such a model.

- 12.15 In Western Power Distribution, capital contributions represent approximately 65% of new business capital expenditure. Therefore the remaining connection costs are supported by Distribution Use of System at 35% of connection costs.
- 12.16 The methods and principles of setting and maintaining cost-reflective tariffs, set out by Boley and Fowler and continued for many years, has shown itself to be a firm basis and a method which is appropriate to electricity distribution pricing. Whilst the method has been adjusted over the years (e.g. for changes in application of the 500MW model to a seven step model instead of a three step model of the network) the changes have been improvements to the method and not a fundamental change to the principles. The method will continue to change slightly as appropriate. For example, with the removal of standing charges yardstick costs for service and connection costs have been built into the method.
- 12.17 Further changes are proposed to the yardsticks to incorporate the changes in connection charge policy agreed with Ofgem for application from April 2001. In this change tariff support allowances will be largely removed except for domestic connections (where a fixed allowance will be retained) and there will be no charges for R&M in connection charges.

### Illustrative Example of Derivation of Use of System Charge

UNITS/kW 3324		Domestic Unrestricted p/kWh
132KV SYSTEM	£/kW/year	0.298
132KV SYSTEM LOSSES	%	0.027
132/33KV TRANSFORMATION	£/kW/year	0.101
132/33KV LOSSES	%	0.008
33KV SYSTEM	£/kW/year	0.065
33KV SYSTEM LOSSES	%	0.005
33/11KV TRANSFORMATION	£/kW/year	0.021
33/11KV LOSSES	%	0.001
11KV SYSTEM	£/kW/year	0.495
11KV SYSTEM LOSSES	%	0.028
11KV/LV TRANSFORMATION	£/kW/year	0.113
11KV/LV LOSSES	%	0.004
LV SYSTEM	£/kW/year	0.466
LV SYSTEM LOSSES	%	0.006
TOTAL 500MW MODEL COSTS		1.638
POWER FACTOR DEVIATION COST		-0.082
SERVICE	£/kW/year	0.168
MISCELLANEOUS COSTS		0.013
SUBTOTAL		1.737
PLUS WORKING CAPITAL		0.013
CONSUMER RELATED COST		0.349
OPERATIONAL RATES		0.198
NGC EXIT CHARGES		0.110
TOTAL YARDSTICK		p/kWh 2.407
FORECAST CONSUMPTION	GWh	3,708
YARDSTICK REVENUE	£m	89.26
TARGET REVENUE	£m	77.13
SCALING	%	86.41%
PRICE	p/kWh	2.08

## Appendix 13 Yorkshire Electricity

### Basis of Charges for Use of System

- 13.1 Where a supply of electricity is provided over electric lines or electrical plant comprising a part of Yorkshire Electricity's distribution system, a charge for use of the system will be levied on the supplier of the electricity.
- 13.2 The charges for each category of supply depend upon the criteria which determine eligibility for that category, such criteria include the voltage of connection to the system, the characteristics of the load and the provision of the type of metering necessary to establish those characteristics.
- 13.3 The charges for use of the system reflect:
- ◆ the costs of providing, operating and maintaining the distribution system to the standards prescribed by the Electricity Act 1989, other than those costs which are recovered through charges paid to Yorkshire Electricity in respect of connection to the system, such that electricity can be transported efficiently through the system to exit points; and
  - ◆ the costs to Yorkshire Electricity of providing services and performing functions for authorised electricity operators, on terms which Yorkshire Electricity is under a duty to offer to such persons under its PES Licence, in order to support the operations of a fully competitive supply market in its authorised area.
- 13.4 The charges for use of the system include a reasonable return on the relevant assets. The revenues arising from the charges are subject to regulation in accordance with the terms of the Licence.
- 13.5 Charges to suppliers for the use of the system are evaluated based on all the assets deployed from Yorkshire Electricity's Grid Supply Points. These charges reflect real electrical flows on the system and the need to provide adequate capacity at all voltage levels to protect the security of the system. However, charges are applied to the electricity as measured at the metered exit points, or equivalent.

### Structure of Use of System Charges.

- 13.6 The Distribution Business' primary objective is to provide the capacity and capability necessary to meet Suppliers' requirements and the measure of this is not units supplied but load capacity. From this it can be viewed that the business of electricity distribution is not a volume-related business, because the costs of distribution are essentially fixed and represent the provision, maintenance, operation and replacement of the system that meets supplier requirements. Consequently the revenue stream in the distribution business should be based on providing an adequate return on these assets and the allocation of costs and resultant charges based on £/kVA/customer.
- 13.7 However, political, regulatory and business factors have mitigated against a purist approach to tariff structures. The government at privatisation wished to avoid significant disturbance to end customers and Use of System charging structures generally mirrored the contemporaneous supply tariff structures. The basis of regulation in the distribution business is 50% volume related (i.e. GWh) - there is therefore an incentive to have charges linked to a unit basis in order to manage the under/over recovery of income.
- 13.8 The charges currently made for use of the system may include some or all of the following elements:
- ◆ a standing charge to cover the costs which do not vary with the extent to which the supply is taken up;
  - ◆ a charge per kVA to cover the system capacity at each relevant voltage level which is attributed to the supply;
  - ◆ charges per kWh (unit) delivered to the exit point from the system, designed to reflect utilisation of the system at all relevant voltage levels. (Unit charges are essentially a proxy for availability charges.)
  - ◆ transaction charges for certain services provided by Yorkshire Electricity on an individual basis when requested by licensed suppliers.
- 13.9 The standing charge for use of the system referred to in the above paragraph may include an amount to reflect the cost of service cable to the premises and its

termination, a contribution to the costs of the local network except as recovered within the connection charge, the costs of use of system metering (where provided), maintaining the customer record, billing and collection and recovery of certain costs associated with the provision of metering point administration services.

### **Formulation of Use of System Charges**

- 13.10 Use of System charges must be non-discriminatory and cost-reflective and must promote the efficient use of the distribution assets. The charges are related to end user characteristics and reflect those assets required to meet the end customers' load on the system.
- 13.11 Use of System charges seek to recover the costs attributable to different classes of customer. The level of charge will differ according to the voltage of the connection and the typical load pattern of the customer. The costs associated with a customer comprise those which are a function of the utilisation of the system (i.e. demand related), and those costs which are customer related.
- 13.12 The costs attributable to the distribution assets for the regulated customer base have been derived from a Yardstick model of the actual costs incurred in the existing system to accommodate the customer load.
- 13.13 This model represents, at each voltage level, the relationship between the capital and ongoing cost of the installed assets and the imposed load resulting from the mix of customers utilising the assets at that voltage. The costs are inclusive of on-costs and are represented at each voltage level as a £/kW value.
- 13.14 These costs are then expressed as annual figures by an annuity factor, which is a function of the allowed regulatory income required. Yardstick costs are then calculated using customer class characteristics derived from earlier load research and studies and expressed as load factor and contribution towards peak demands (coincidence factor) on the distribution system. Also included in these yardstick costs are allocations of rates, National Grid Company Exit charges and power factor adjustments.
- 13.15 Customer-related costs are separately modelled on a yardstick model which allocates the costs of meter provision and maintenance; capital and ongoing

service and cut-out costs; meter reading, billing and collection costs; contribution to the costs of the local network (except as recovered within the connection charge); and costs of tariff support given for connection charges as appropriate.

- 13.16 From these yardstick costs, and forecasts of units distributed, DUoS charges are formulated. The charges are structured in different ways, from a single unit rate and a fixed charge for general domestic customers, to a combination of fixed, availability and multiple unit rates for monthly- billed customers.
- 13.17 The process above describes a purist view of charge setting, and is the basis of our current charging structure. However, in recent years the methodology has been amended to accommodate a price freeze in 1999/2000 and outcome of DPCR3 in 2000/2001. The latter, with its substantial  $P_0$  factor and exclusion of data retrieval, data aggregation and data processing costs necessitated the introduction of scaling of the charges derived from the yardstick model in order to ensure that the required allowed regulatory income was correctly recovered.
- 13.18 We are currently in the process of introducing a new updated version of the 500MW long-run marginal cost model. The output from this will be indicative charges for individual LLFC's, and it is intended that this will form the basis of our future DUoS charges. The model itself has been developed by the Electricity Association and uses the principles of long-run marginal cost to provide an economically efficient and stable pricing structure. It also shows how to base the charges for use of the network on the costs of meeting an increment in demand, rather than relating them to the actual year-by-year expenditure on network engineering. This charge is calculated using the most recent actual accounting costs, since these offer a reasonable approximation to the long-run marginal cost for this element, and are reasonably easy to obtain.

13.19 The table below shows the variations in tariffs for a domestic unrestricted customer and the overall movement in the average domestic pence per unit, over the past 3 years.

	<b>1998/1999 Actual</b>	<b>1999/2000 Actual</b>	<b>2000/2001 Forecast</b>
<b>Domestic UR Fixed Charge (p/day)</b>	5.26	5.26	5.26
<b>Domestic UR Unit Charge (p/unit)</b>	1.68	1.68	1.19
<hr/>			
<b>Annual Domestic Income (£m)</b>	156.7	158.7	129.3
<b>Annual Units Domestic Distributed (GWh)</b>	7,351	7,471	7,876
<b>Average Charge (p/unit)</b>	2.1	2.1	1.6*

\* note: the average charge for 2000/01 excludes DR, DA and DC costs

13.20 Use of System charges for EHV customers are calculated on a site-specific basis. This allows for the individual nature of these supplies, in terms of load characteristics and capital, to be fully considered.

13.21 From the above it can be seen that the basis of formulation of use of system charges is essentially similar to that method outlined in Boley & Fowler (1977). Load research is no longer carried out across the industry as described in Boley and Fowler, and consequently the derivation of load factors and coincidence factors was latterly based more on experience and past figures than on first principle load research. Also external regulatory pressures have moved charges away from those derived directly from yardstick models and necessitated scaling to ensure financial targets are met.

#### **Tariff Support Allowances**

13.22 Yorkshire Electricity provide tariff support allowances for domestic connections only. The average level of housing contribution over the last three years has been 70%, resulting in around 30% of connection costs being recovered through UoS tariffs.

#### **Network Operating and Maintenance Costs**

13.23 In the past the costs associated with the operation, repair and maintenance of the system were bundled and expressed as a percentage of the gross fixed asset values of each asset group. This figure was then added to the annuity factors,

expressed as percentages, established to give the appropriate rate of return for each asset group. The activities comprise;

*Operation*; costs associated with the function of control and co-ordination with the aim of meeting the requirements of the Distribution Code. Includes the costs of the Control Centre.

*Repair*; those costs associated with returning the network to its optimum designed condition subsequent to the occurrence of damage caused by third parties, environmental conditions, or equipment failure.

*Maintenance*; those costs associated with the function of preventative maintenance carried out with the aim of preventing equipment failure and optimising equipment life.

The costs of these activities are closely monitored within the business and analysed to ensure efficient levels of spending.

### **Electrical Losses**

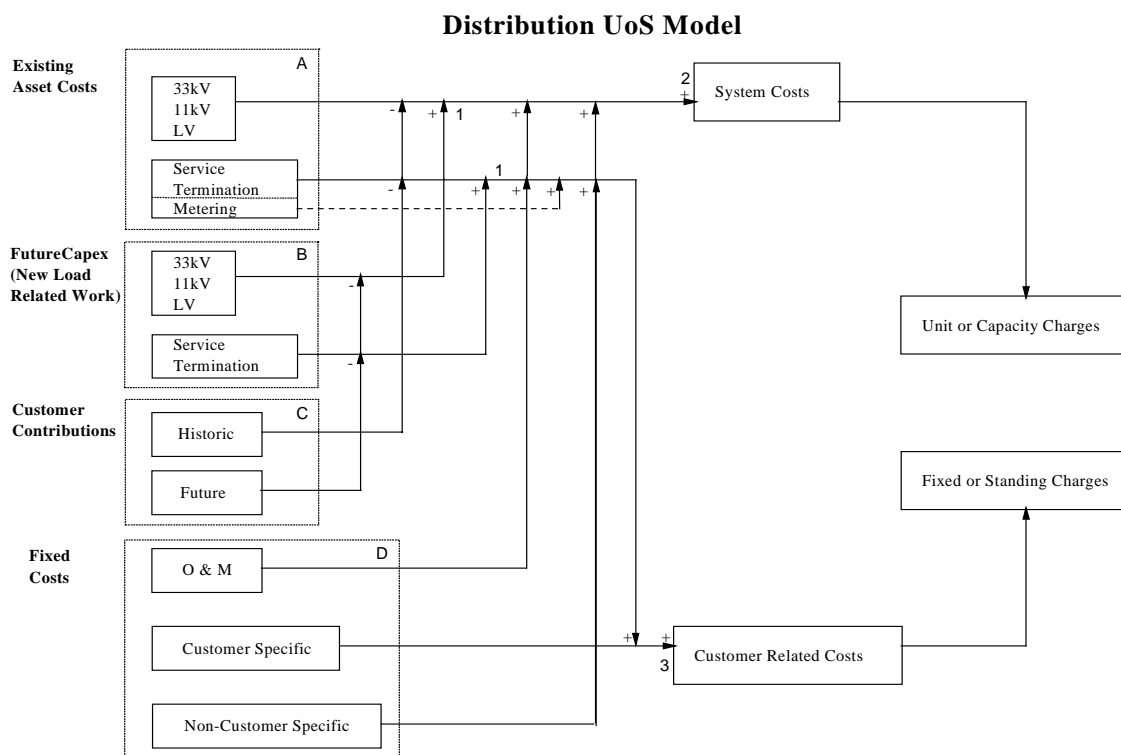
- 13.24 Within the distribution regulatory formula there is a factor to take into account the impact of electrical losses on the distribution network. This factor contributes to the determination of our allowed income and can act to increase or decrease it. Whichever the outcome, the effect is spread over the entire regulated customer base.

## Appendix 14 Scottish & Southern Energy (Scottish Hydro-Electric)

### Introduction

- 14.1 The methods and principles used to derive Distribution Use of System (DUoS) charges are based broadly on the original principles outlined by Boley and Fowler and implemented by the Electricity Council (EC) in their Tariff Formulation Model. Over the years since privatisation of the industry, Scottish and Southern Energy (SSE) has developed and amended its model to reflect more accurately the cost drivers and consumption patterns associated with its specific network.
- 14.2 Whilst the EC approach was based upon a 500 MW model designed to reflect a typical REC distribution network, this model was not particularly reflective of the SSE network. Until 1995, SSE used a stylised 50 MW version of the model. Reflecting the different structure of the industry in Scotland, the SSE model for distribution did not include 132 kV assets, nor did it take account of a bulk supply tariff, as this did not apply in Scotland.
- 14.3 During 1995, SSE developed a new DUoS model, principally to separate its distribution charges from supply tariffs. As SSE is required by its licence to seek Ofgem approval of its charging statement (including the DUoS tariffs), SSE and OFFER (Scotland) spent many hours in discussion before the new model was introduced.
- 14.4 The new tariff model, first used to set tariffs for the year 1996/97, differs from the traditional 500 MW in a number of small ways. The first difference is that, as SSE currently charges its transmission Exit charges directly to suppliers, the distribution tariffs produced are not required to allow for the pass-through of transmission charges. As we discuss the operation of the SSE model in the following paragraphs, we shall indicate the ways in which this model may differ from the EC tariff model.
- 14.5 The SSE model creates tariffs by following three main steps. First, the distribution costs to be recovered are split into two types - "system" costs and

“customer related” costs. The system costs are then hypothecated to different customer groups on the basis of the demand placed on the system by those customers. Finally, the costs allocated to each customer group are converted into the tariffs through which suppliers will be charged for their customers’ use of the distribution system. The following diagram may help to illustrate how the costs are collected and processed by the SSE DUoS tariff model.



### Allocation of Costs

14.6 The first difference between the new SSE model and the EC 500 MW model is that network costs are not based on an incremental (50 or 500 MW) network. Instead, SSE uses a modern replacement value model of its whole distribution network, with the asset value at each distribution voltage being calculated. These asset values have an annuity factor applied to them, to ensure that revenue collected through the tariffs matches the income allowed by the price control i.e. the costs in Box A of the diagram are “scaled” to ensure that revenue from the tariffs matches allowed income. The annuity factor applied allows for depreciation of the distribution assets, along with non-load related capital expenditure (e.g. refurbishment). Historic customer contributions (Box C) are

subtracted from the annuitised asset value for each voltage level, whilst future load related capex (Box B) (net of expected customer contributions (Box C)) is added to the annuitised asset cost to give a total "capital" cost for each voltage level. Thus we have reached the points "1" in the diagram.

- 14.7 Each year, the model is updated to reflect the addition and removal of assets at each voltage level. Historic capital expenditure and customer contribution figures are revised annually, with new forecasts for future capex and customer contributions also being incorporated.
- 14.8 Operating costs for the distribution system (included in Box D) are also collected through the DUoS tariffs. These fixed costs are split into operation and maintenance costs, non customer specific costs and customer specific costs. O&M costs, which include wayleave costs and repair and maintenance costs for all assets, are attributed to the different asset types. Other non customer specific costs, which include rates, are also spread across the assets at the different voltage levels. Other operating costs, including billing and communications costs are not related to assets in any way and, instead, they are regarded as customer specific costs. These costs are collected through fixed (or "standing") charges.
- 14.9 Operating costs are updated each year and are based on the actual costs incurred in the most recently completed financial year (as this is the best indicator of the likely level of cost for each activity).
- 14.10 Thus all of the cost inputs to the model, shown down the left-hand side of the diagram, have been gathered into two groups - asset related costs (at point 2 of the diagram) and customer specific operating costs (at point 3). The asset related costs are then split into two - system costs and customer related costs. System costs are those which are driven by demand on the assets and this category includes the costs associated with the LV, HV and EHV assets. Asset costs for metering (up to 1999/2000), services and terminations are driven more by the existence of the customer than by the customer's demand on the assets and hence they are treated as customer related costs, to be collected through fixed/standing charges, along with customer specific operating costs.

### **Apportioning Costs to Customer Groups**

14.11 The next step towards producing DUoS tariffs is to apportion the costs to be recovered to the various customer groups who are making use of the distribution system. In the past, distribution tariffs have been closely aligned with supply tariffs, indeed Boley/Fowler indicate the method by which the distribution components of specific supply tariffs (e.g. domestic unrestricted or industrial 50% load factor EHV) may be derived. In adopting its new distribution tariff model SSE severed the links with supply tariffs, by moving to a very few customer groups - domestic standard, non domestic standard, restricted consumption (domestic or non domestic), LVMD, HVMD, EHVMD and public lighting.

#### **Customer Related Costs**

14.12 The fixed charge for each customer group allows the distribution business to recover all of the customer related costs associated with that type of customer. The standing charge therefore recovers all of the costs associated with a service cable and termination (including O&M, a return on the asset, depreciation and refurbishment costs, along with average billing and customer service operating costs). Until 1999/2000, metering costs for non half-hourly meters were also recovered through the distribution standing charge. From April 2000, this is no longer the case.

#### **Network Related Costs**

14.13 In accordance with the principles proposed by Boley/Fowler, the SSE tariff model apportions the network costs for each voltage level between the customer groups on the basis of the demand placed on that part of the network by each customer type. Thus, the tariffs will collect revenue from those using the network at times of the peak demand. In allocating costs to the various customer groups, published loss adjustment factors are used to take account of the different losses associated with customers connected at different voltage levels and the effect of those losses upon the customers' demand as seen at each voltage level.

14.14 The standard EC 500 MW model apportioned these costs on the basis of diversified demand at each voltage level. The SSE model has been amended to reflect the fact that a non-domestic customer's demand is not well diversified at

the voltage level at which it is connected. Our model therefore takes some account of the undiversified demand for non-domestic customers connected at each voltage level.

- 14.15 Costs are allocated to customer groups on the basis of their demand on each part of the network at three “mini-peaks” during a typical, winter day. These three peaks reflect a business start-up peak, a domestic tea-time peak and an evening peak which occurs when “off-peak” units are switched on. The three peaks are used to reflect the fact that, uniquely in the UK, the SSE system demand over a 24 hour period in winter is reasonably flat. Low gas penetration in the north of Scotland means that a very high number of customers rely on electric storage heating systems which, not infrequently, can lead to peaks of demand on certain parts of the network. It is important that SSE reflects this cost driver, but as suppliers in the north of Scotland are obliged to offer the same terms to similar customers across the territory, we have avoided using geographical price signals for this “off-peak” load. Instead, we use a peak in the day which includes some of the electrical heating load, to ensure that these customers contribute to the distribution system costs.

### **The Structure of the Tariffs**

- 14.16 Now that we have allocated the appropriate costs to each customer group, the next step is to derive an appropriate tariff structure to allow those costs to be recovered from the customers. SSE’s DUoS charges are comprised of some or all of the following components: a fixed (or “standing”) charge per day or month; a capacity (or availability) charge per kVA of capacity and a unit charge (or charges) per kWh of consumption.

## Customer Related Costs

- 14.17 Recovery of customer related costs is quite straightforward, in that the total customer related costs allocated to a particular customer group is simply divided by the forecast customer number (or, rather, the forecast MPAN count) for the group to derive an annual fixed charge per customer (or per MPAN). This charge is then converted to a pence per day charge and is published on that basis to allow suppliers to calculate the precise charge that they will incur when they pick up a new customer, say, 100 days into a new financial year.

## System Costs

- 14.18 The costs associated with the system are recovered either through unit charge(s) (p/kWh) or through unit charge(s) (p/kWh) plus capacity charges (p/kVA/day).
- 14.19 For customers with maximum demand metering, the costs of the assets “close” to their connection point are collected through capacity charges. This methodology reflects the fact that, when a customer’s connection is made, their connection agreement effectively allows them to reserve a specific capacity entitlement on the system. The costs associated with higher voltage levels are recovered through unit charges. Thus, for a LV maximum demand customer, LV system costs will be recovered on a “pence per kVA of capacity per day” basis, whilst HV and EHV system costs will be recovered on a “pence per kWh” basis.
- 14.20 Capacity charges are derived by dividing the total system cost apportioned to the customer group for its connection voltage, divided by the total authorised capacity for the customers in the group (expressed in kVA). The authorised capacity divisor is updated each year to reflect the latest forecast of customer numbers and average authorised capacity for the group.
- 14.21 Unit charges for MD customers are derived by dividing the total system costs for voltage levels above the connection level by the forecast units distributed to those customers during the charging year. Unit charges for maximum demand customers are then weighted on the basis of consumption during winter versus summer months. This normally means that winter units are more expensive than summer units, reflecting the fact that winter consumption drives system costs

more than summer consumption. Sales forecasts and weighting factors are updated each year.

14.22 A variation to the rules above is made for EHV customers. Following the standard rules for MD customers, EHV system costs would be recovered through capacity charges and, as there is no higher distribution voltage level than EHV, unit charges would be zero. This type of tariff would certainly allow the distribution business to recover an appropriate level of revenue, but it was rejected for a number of reasons. Firstly, a zero unit charge could encourage customers to consume an infinite number of units - a situation which would not deliver the correct messages regarding energy efficiency or efficient use of the system. Secondly, for some EHV customers with high authorised capacities, but who do not consume many units, recovery of all costs through capacity charges could be seen as unfairly punitive. In order to avoid these issues, a proportion of EHV costs are recovered from EHV customers on a "pence per kVA of capacity per day" basis, with the remainder collected on a "pence per kWh" basis.

14.23 Finally, all of the system costs apportioned to each group of non-MD customers are converted to a "pence per kWh of consumption" tariff. This calculation takes all of the costs to be recovered from a particular group and divides by the total forecast consumption for the group. The divisors for these calculations are updated each year, based on the latest forecasts of customer numbers and average consumption for each customer type.

### **Conclusion**

14.24 The above narrative describes how the SSE distribution tariff model currently derives DUoS tariffs. As the SSE model was introduced relatively recently, we do not anticipate making any major changes in our tariff setting methodology. The one area that we are considering is the development of EHV charges, where it may be appropriate to introduce site specific use of system charges.